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Economic Impact Analysis for the Mandatory Reporting of Greenhouse Gas Emissions Subpart RR: Proposed Carbon Dioxide Injection and Geologic Sequestration Reporting Rule

Draft Report

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SECTION 1
INTRODUCTION AND BACKGROUND

1.1 Mandatory Reporting Rule Background

On December 26, 2007, President Bush signed the fiscal year Consolidated Appropriations Act authorizing funding for EPA to issue a rule requiring the mandatory reporting of greenhouse gas (GHG) emissions (Consolidated Appropriations Act, 2008, Pub. L. No.110-161, 121 Stat 1844, 2128 (2008)). An accompanying joint explanatory statement directed EPA to "use its existing authority under the Clean Air Act" to develop a mandatory GHG reporting rule.

The Proposed Mandatory Reporting of Greenhouse Gases Rule was signed on March 10, 2009, by Administrator Lisa Jackson; and EPA published a proposed rule requiring mandatory reporting of GHG emissions in April 2009. 74 FR 16448 (April 10, 2009). After a 60 day comment period, two public hearings, and meeting with over 4,000 additional people in over 150 groups via Webinars, conferences, individual meetings, and other forms of outreach EPA issued a final rule on October 30, 2009. 74 FR 56260. The Mandatory Reporting of Greenhouse Gases Rule requires reporting of GHGs and supply from all sectors of the economy, including fossil fuel suppliers, industrial gas suppliers, and direct emitters of GHGs. The rule does not require the control of greenhouse gases; rather the rule requires specific source categories that are above certain threshold levels to monitor and report those emissions.

The final Mandatory Reporting of Greenhouse Gases Rule covers the major GHGs that are directly emitted by anthropogenic activities. These include carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), hydroflourocarbons (HFCs), perfluorocarbons (PFCs), sulfur hexafluoride (SF_6), and other specified fluorinated compounds (e.g., hydroflouroethers (HFEs)) used in boutique applications such as electronics and anesthetics. [1]

The final rule contains 31 subparts, each requiring reporting from a defined source category. In order to meet the reporting time, quality assurance, and verification requirements of the rule, EPA is establishing a facility-to-EPA electronic reporting system to facilitate collection of data under this rule. All facilities that are covered under this rule as reporters will use this data system to submit required data.

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[1] These gases influence the climate system by trapping in the atmosphere heat that would otherwise escape to space. Additional information about GHGs, climate change, and climate science, and other related issues, can be found at EPA's climate change web site at http://www.epa.gov/climatechange/.

1.2 Supplemental Proposal of Subpart RR: CO_2 Injection and Geologic Sequestration

Today, EPA is proposing to amend the Mandatory Reporting of Greenhouse Gases Program at 40 CFR part 98 to add reporting requirements covering facilities that conduct injection and geologic sequestration (GS) of CO_2.

EPA is proposing a tiered approach for reporting requirements under this subpart. The first tier of proposed regulations would establish a set of reporting requirements that would cover all facilities that inject CO_2 underground. All facilities would be required to report the amount of CO_2 transferred onsite from offsite sources, the source of the CO_2 (if known), and the amount of CO_2 injected underground.

The second tier of reporting requirements would apply to GS facilities. GS facilities would be required to calculate the amount of CO_2 sequestered by subtracting total CO_2 emissions from the quantity of CO_2 injected in the reporting year. The emitted quantity would include the amount of the injected CO_2 that leaked from the subsurface to the surface (if any), CO_2 produced with oil or natural gas where ER operations are conducted at the GS facility, and fugitive or vented CO_2 emissions from surface equipment.

EPA considered several options for monitoring, reporting and verification (MRV) of potential CO_2 leakage[2] at GS sites: do not require a MRV plan, require a universal MRV plan that applies to all GS sites, or require a site-specific MRV plan. EPA is proposing to require monitoring according to a site-specific MRV plan, but is seeking comment on all of the options considered. While the risk of leakage at a well-selected and well-managed GS site is expected to be low, the Agency considers it important for all facilities conducting GS to demonstrate that they have met MRV standards.

Data on CO_2 injection and GS are critical to informing Clean Air Act (CAA) GHG policies. This data would provide information and transparency on the amount of CO_2 injected and geologically sequestered in the United States and, in combination with other subparts of the MRR, would enable EPA to track the flow of CO_2 across a CCS system. In addition, this information would enable EPA to monitor the growth and efficacy of GS (and therefore CCS) as a GHG mitigation technology over time and to evaluate relevant policy options. For example, EPA would be able to track whether incentives or regulations are needed to encourage faster or further GS project development. EPA would also be able to track whether ER sites are transitioning to GS and consider whether incentives or regulations are needed. Where ER

[2] Leakage in this proposed rule is defined as the movement of CO_2 from the injection zone to the surface (for example to the atmosphere, indoor air, oceans or surface water).

facilities are reporting GS, EPA would be able to evaluate ER as a potentially non-emissive end use. In combination with other subparts of the MRR, EPA would be able to reconcile this data with CO_2 supplied (subpart PP) in order to better understand the quantity of CO_2 supplied to emissive and non-emissive end uses.

In developing this proposal, EPA considered overlap between this program and other programs. In July 2008, EPA proposed to amend its UIC program to establish a new class of injection well for GS projects (73 FR 43492 (July 25, 2008)). Today's proposal provides a pathway for CO_2 injection facilities to report to EPA as GS facilities under the CAA, regardless of their UIC permit classification. Under this proposal, any facility sequestering CO_2 underground can choose to report as a GS facility for purposes of this proposed rule.

Since subpart RR is an amendment to the MRR, the general provisions of that rule (40 CFR part 98, subpart A) apply to today's rule unless a provision is superseded by this subpart that applies uniquely to facilities that inject CO_2 or that conduct GS. The general provisions address the following topics: the purpose and scope (40 CFR 98.1); who must report (40 CFR 98.2); the general monitoring, reporting, recordkeeping and verification requirement (40 CFR 98.3); the authorization and responsibilities of the designated authority (40 CFR 98.4); how a report is submitted (40 CFR 98.5); definitions (40 CFR 98.6); the standardized methods incorporated by reference (40 CFR 98.7); the compliance and enforcement provisions (40 CFR 98.8); and the mailing addresses (40 CFR 98.9).

In a separate rulemaking package that should shortly follow this proposal, EPA will be issuing minor harmonizing changes to the general provisions for the MRR (40 CFR part 98, subpart A) to accommodate the addition of the proposed CO_2 injection and geologic sequestration subpart. The changes affect paragraphs on rule applicability, schedule, definitions, and incorporation by reference.

In particular, EPA is proposing to revise 40 CFR 98.2(a) to add CO_2 injection and geologic sequestration facilities to the list of source categories that must report starting with calendar year 2011. EPA also is proposing to restructure 40 CFR 98.2(a) to move the lists of source categories from the text into tables. The table format improves clarity and facilitates the addition of source categories that were not included in calendar year 2010 reporting and begin reporting in future years. Because all CO_2 injection and geologic sequestration facilities (as defined in proposed 40 CFR part 98, subpart RR) would be subject to the proposed rule, this source category would be added to the table of "all-in" source categories referenced from 40 CFR 98.2(a)(1). The introductory text of 40 CFR 98.2(a)(1) and a few other sentences throughout 40 CFR part 98, subpart A that reference "subparts C through JJ" would be reworded to accommodate proposed new subparts such as RR that are outside of this range of letters. These rewordings either refer to the source category tables or otherwise correct the range of subparts referenced, as appropriate. In addition, EPA is proposing to amend 40 CFR 98.2 (1) to accommodate a mechanism that would allow CO_2 injection and GS facilities to cease reporting.

EPA is proposing to amend 40 CFR 98.2(a) so that the MRR applies to facilities located on or under the Outer Continental Shelf. These revisions are necessary to ensure that any CO_2 injection or GS facilities located on or under the Outer Continental Shelf of the United States would be required to report under this rule. In addition, EPA is proposing revisions to the definition of United States to clarify that the United States includes the territorial seas. Other facilities located offshore of the United States covered by the MRR program at 40 CFR part 98 would also be affected by this change in the definition of United States. For example, EPA is intending to revise the MRR requirements to add a new subpart, subpart W, to address petroleum and natural gas systems. Finally, in addition to the change to the definition of United States, EPA is adding a definition of "Outer Continental Shelf." This definition is drawn from the definition in the U.S. Code. Together, these changes make clear that the MRR applies to facilities on land, in the territorial seas, or on or under the Outer Continental Shelf, of the United States, and that otherwise meet the applicability criteria of the rule.

EPA is proposing to revise 40 CFR 98.3(b), which establishes the schedule for annual reporting. The text in 40 CFR 98.3(b)(1) and (b)(2) indicate that existing facilities subject to the rule must submit an annual GHG report for calendar year 2010. When proposed subpart RR is added, facilities will become subject to the reporting rule due to CO_2 injection or geologic sequestration, and their first annual GHG report would cover calendar year 2011 rather than 2010. Therefore, EPA is proposing to modify the text of 40 CFR 98.3(b) to allow reporting to start in different years, as appropriate. EPA also is proposing to remove and reserve 40 CFR 98.3(b)(1). It would no longer be accurate, and it would not be needed because 40 CFR 98.2(a) would indicate the first reporting year for source categories added to the rule and the requirement for facilities to report in each subsequent year is already contained in 40 CFR 98.2(i).

EPA is proposing to amend 40 CFR 98.6 to add definitions for terms used in the proposed subpart. EPA also is proposing to amend 40 CFR 98.7 (incorporation by reference) to include standard methods used in proposed subpart RR.

1.3 Subpart RR Context

Subpart PP requires the reporting of CO_2 supplied to the economy. Subpart PP applies to all facilities with CO_2 production wells, facilities with production process units that capture and supply CO_2 for commercial applications or that capture and maintain custody of a CO_2 stream to sequester or otherwise inject it underground, and to importers and exporters of bulk CO_2. During the public comment period on the rule, EPA received many comments on subpart PP that CO_2 injected underground should be considered when estimating emissions from the CO_2 supply industry.

Some commenters specified that some of the CO_2 supplied for the purposes of enhanced oil and gas recovery (ER) is additionally sequestered rather than emitted and characterized ER operations as "closed systems" rather than emissive. Other commenters stated that including reporting requirements for geologically sequestered CO_2 would fill a critical gap in the reporting system. EPA agrees that ER is a potentially non-emissive end use and that GS data reporting from ER sites can assist EPA in quantifying the amount of CO_2 that is permanently and securely geologically sequestered. In addition, EPA agrees that GS reporting requirements would provide information and transparency on the amount of CO_2 injected and geologically sequestered in the United States.

Although CCS is occurring now on a relatively small scale, it could play a larger role in mitigating GHG emissions from a wide variety of stationary sources. According to the Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2007, stationary sources contributed 67 percent of the total CO_2 emissions from fossil fuel combustion in 2007.[3] These sources represent a wide variety of sectors amenable to CO_2 capture: electric power plants (existing and new), natural gas processing facilities, petroleum refineries, iron & steel foundries, ethylene plants, hydrogen production facilities, ammonia refineries, ethanol production facilities, ethylene oxide plants, and cement kilns. Furthermore, 95 percent of the 500 largest stationary sources are within 50 miles of a candidate CO_2 reservoir[4]. Estimated GS capacity in the United States is over 3,500 Gigatons CO_2 ($GtCO_2$) (13,000 Gigatons CO_2 at the high end),[5] although the actual capacity may be lower once site-specific technical and economic considerations are addressed.

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[3] U.S. EPA Draft Inventory of U.S. Greenhouse Gas Emissions and Sinks, 1990-2007, Draft Report, EPA 430-R-09-004. Available at: http://epa.gov/climatechange/emissions/usinventoryreport.html.

[4] Dooley, JJ, CL Davidson, RT Dahowski, MA Wise, N Gupta, SH Kim, EL Malone. 2006. "Carbon Dioxide Capture and Geologic Storage: A Key Component of a Global Energy Technology Strategy to Address Climate Change." Joint Global Change Research Institute, Battelle Pacific Northwest Division. PNWD-3602.

[5] DOE. 2008. Carbon Sequestration Atlas of the United States and Canada (Atlas II). Available at: http://www.netl.doe.gov/technologies/carbon_seq/refshelf/atlasII/.

Even if only a fraction of that geologic capacity is used, CCS is poised to play a sizeable role in mitigating U.S. GHG emissions.

Many of the injection and monitoring technologies that may be applicable for GS are commercially available today and will be more widely demonstrated over the next 10 to 15 years.[6] The oil and natural gas industry in the United States has over 35 years of experience in transporting and injecting CO_2 into the deep subsurface for the purposes of enhancing oil and natural gas production. This experience provides a strong foundation for the injection and monitoring technologies that will be needed for commercial-scale CCS. U.S. experience with ER combined with the experience of four end-to-end commercial CCS projects[7] and ongoing research, demonstration, and deployment programs throughout the world, are building confidence that transportation and sequestration of large volumes of CO_2 can be achieved.

[6] Dooley, JJ, CL Davidson, RT Dahowski. 2009. "An Assessment of the Commercial Availability of Carbon Dioxide Capture and Storage Technologies as of June 2009." Joint Global Change Research Institute. Pacific Northwest National Laboratory. PNNL-18520.

[7] These projects are: Sleipner (Norwegian North Sea)- 1 Mt CO_2/yr injected since 1996; Weyburn (Canada)- 1 Mt CO_2/yr injected since 2000; In Salah (Algeria)- 1.2 Mt CO_2/yr injected since 2004; and Snohvite (Norwegian Barents Sea)- 0.7 Mt CO_2/yr injected since 2008.

SECTION 2
REGULATORY BACKGROUND

The intent of the MRR is to collect accurate and timely GHG data that can be used to inform future policies. Although the mandatory GHG rule is unique, EPA carefully considered other federal and state programs during development of the rule. The reporting program will supplement rather than duplicate other U.S. government GHG programs. We outline EPA's overall rulemaking approach, sources considered, and summarize our review of GHG monitoring protocols for each source category used by federal, state, regional, and international voluntary and mandatory GHG programs, and our review of state mandatory GHG rules below. The remainder of the section provides an overview of related existing programs and discusses their relevance in the development of Subpart RR.

2.1 EPA's Overall Rulemaking Approach

The mandatory reporting program will provide comprehensive and accurate data which will inform future climate change policies. Potential future climate policies include research and development initiatives, economic incentives, new or expanded voluntary programs, adaptation strategies, emission standards, a carbon tax, or a cap-and-trade program. Because we do not know at this time the specific policies that will be adopted, the data reported through the mandatory reporting system should be of sufficient quality to support a range of approaches. Also, consistent with the Appropriations Amendment, the reporting rule covers a broad range of sectors of the economy.

To these ends, we identified the following goals of the mandatory reporting system:

- Obtain data that is of sufficient quality that it can be used to support a range of future climate change policies and regulations.
- Balance the rule coverage to maximize the amount of emissions reported while excluding small emitters.
- Create reporting requirements that are consistent with existing GHG reporting programs by using existing GHG emission estimation and reporting methodologies to reduce reporting burden, where feasible.

This section presents the current regulatory context for Subpart RR and illustrates the anticipated role of the current proposal within the framework of the existing mandatory and voluntary programs.

2.2 Statutory Authority

EPA is proposing this rule under the existing authority provided in CAA section 114. As noted in the Mandatory Reporting of GHG Rule, CAA section 114 provides EPA with broad authority to require information mandated by this rule because such data will inform and are relevant to EPA's carrying out a wide variety of CAA provisions (74 FR at 66264). Under CAA section 114(a)(1), the Administrator may require emissions sources, persons subject to the CAA, or persons whom the Administrator believes may have necessary information to monitor and report emissions and provide such other information as the Administrator requests for the purposes of carrying out the provisions in the CAA (except for a provision of title II with respect to motor vehicles).

As discussed in greater detail in the response to comments for the final Mandatory Reporting of GHG Rule, the CAA provides EPA with broad authority to require the comprehensive and accurate information mandated in this rule because such data will inform, and are relevant to, EPA's analyses of various CAA provisions.

The information from CO_2 injection and GS facilities will allow EPA to make well-informed decisions about whether and how to use the CAA to regulate these facilities and encourage voluntary reductions.

2.2 Safe Water Drinking Act and UIC Regulations

EPA's UIC program was established in the 1970s to prevent endangerment of underground sources of drinking water (USDWs) from injection of various fluids, including CO_2 for ER, oil field fluids, water stored for drinking water supplies, and municipal and industrial waste. The UIC program, which is authorized by Part C of the Safe Drinking Water Act (SDWA) (42 U.S.C. 300h et seq.), is designed to prevent the movement of such fluid into USDWs by addressing the potential pathways through which injected fluids can migrate and potentially endanger USDWs.

When EPA initially promulgated its UIC program regulations, the Agency defined five classes of injection wells at 40 CFR 144.6, based on similarities in the fluids injected, construction, injection depth, design, and operating techniques. Wells injecting industrial nonhazardous liquids, municipal wastewaters or hazardous wastes beneath the lowermost USDW are categorized as Class I. Those injecting fluids in connection with conventional oil or natural gas production, enhanced oil and gas production, and the storage of hydrocarbons which are liquid at standard temperature and pressure are categorized as Class II. Class III wells inject fluids associated with the extraction of minerals, and those categorized as Class IV inject hazardous or radioactive wastes into or above USDWs. Class IV injection wells are banned unless authorized under an approved Federal or State ground water remediation project. Class V includes all injection wells that are not included in Classes I–IV. This well class provides for Class V experimental technology wells including those permitted as GS pilot projects.[8]

In 2008, EPA proposed to amend the UIC program to establish a new class of injection well — Class VI — to cover the underground injection of CO_2 for the purpose of GS, or long-term storage of CO_2 (73 FR 43492 (July 25, 2008)). The proposed requirements would tailor existing components of the UIC program to address the unique nature of GS projects so as to ensure that the injection of large volumes of CO_2 in a variety of geologic formations for the purposes of long term storage would not endanger USDWs. The UIC Class VI proposal does not require any facilities to capture and/or sequester CO_2; rather the proposed requirements, if finalized, would protect USDWs under the SDWA. The SDWA does not provide authority to develop regulations for all areas related to GS such as capture or transport. As outlined in the UIC Class VI proposal, injection wells used for injecting CO_2 for the purposes of ER would continue to be regulated and permitted as Class II as long as any production is occurring.

Facilities regulated under the UIC program are required to collect and report data, with minimum requirements for the collection and reporting of data established at the federal level. Where states are given primacy over the UIC program, the data collected under the UIC program varies. Data currently collected under a state-issued UIC permit is submitted to states while, under today's subpart RR proposal, reporters will be submitting data directly to EPA. The Agency believes that state, local, and tribal input is valuable in ensuring that the subpart RR reporting requirements appropriately build on the UIC program requirements.

Today's proposal builds on the UIC program requirements for monitoring with the additional goals of verifying the amount of CO_2 sequestered and collecting data on CO_2 surface emissions from GS facilities. EPA is proposing that a facility's UIC permit may be used to demonstrate that certain MRV plan requirements have been fulfilled.

[8] See EPA UIC Guidance #83. Available at: http://www.epa.gov/safewater/uic/wells_sequestration.html

In the Agency's August 2009 Notice of Data Availability supplementing the UIC Class VI proposal, EPA noted that it was evaluating the need for a more comprehensive regulatory framework for GS. The Agency acknowledges that regulatory clarity is essential for enabling GS to move forward in a manner that protects human health and the environment. EPA is coordinating GS requirements across relevant statutory or other programs in order to minimize redundancy and increase clarity for stakeholders.

The proposed UIC Class VI rule is a separate rulemaking action; the comment period for that rulemaking closed on December 24, 2008. EPA will not be accepting or responding to comments on the proposed UIC Class VI rule through today's proposal unless related to a specific issue raised by this action.

2.3 Other Federal, State, and Agency Programs

The Department of Energy (DOE) Energy Information Administration implements a voluntary GHG reporting program under section 1605(b) of the Energy Policy Act of 1992, which directed DOE to issue guidelines establishing a voluntary greenhouse gas reporting program (42 U.S.C. 13385(b)). Under the Energy Information Administration's "1605(b) program," reporters can choose to prepare an entity-wide GHG inventory and identify specific GHG reductions made by the entity.[9] Reporting tools were revised and published in 2009 to assist entities in preparing a preliminary estimate of emissions. The 2007 updated 1605(b) guidance outlines a voluntary process to report data on CO_2 sequestration. Currently, no CO_2 injection or sequestration entity has reported under the 1605(b) program per the 2007 guidelines. According to the Energy Information Administration website, the first reporting cycle under the revised Voluntary Reporting of Greenhouse Gases Program has not been completed as of January 15, 2010. The Energy Information Administration anticipates issuing an annual report and public use database for data reported through 2008 by early 2010.[10] The 1605(b) guidance requires the implementation of a site-specific monitoring plan, but this plan is not evaluated by DOE to determine whether the plan will provide for appropriate monitoring. Four prescriptive monitoring scenarios are offered with grades ranging from "A" to "C", any of which would be acceptable for compliance with the 1605(b) program. Furthermore, although the 1605(b) guidance cites the importance of reporting CO_2 leakage should it occur, the guidance does not include a discussion of, procedures for, or methodologies for using monitoring technologies and

[9] Under the 1605(b) program an "entity" is defined as "the whole or part of any business, institution, organization or household that is recognized as an entity under any U.S. Federal, State or local law that applies to it; is located, at least in part, in the U.S.; and whose operations affect U.S. greenhouse gas emissions." (http://www.pi.energy.gov/enhancingGHGregistry/)

[10] http://www.eia.doe.gov/oiaf/1605/data_reports.html

techniques to quantify the leakage. As a result of this, and the fact that reporting is voluntary, the 1605(b) program would not meet the data needs of this proposed rule.

The Internal Revenue Service (IRS) made public IRS Notice 2009-83 Credit for Carbon Dioxide Sequestration under section 45Q on its Web site on October 8, 2009.[11] The notice provides procedures for the allocation of credits for CO_2 sequestration under section 45Q of the Internal Revenue Code. Section 45Q was enacted by section 115 of the Energy Improvement and Extension Act of 2008, (October 3, 2008) and was amended by section 1131 of the American Recovery and Reinvestment Act of 2009 (February 17, 2009). To claim this credit, a taxpayer must follow general monitoring and verification principles, calculate CO_2 sequestered in the fiscal year using a mass-balance equation, and report to IRS the amount of qualified CO_2 sequestered in the fiscal year. Seventy-five million metric tons of qualified CO_2 can be taken into account for this credit. The IRS included a provision in the notice to supersede its monitoring and verification procedures and requirements with procedures and requirements finalized by EPA in future GS rulemaking such as the UIC Class VI proposal and this proposed rule.

EPA has concluded for a number of reasons that the IRS data would not meet the needs outlined in this proposed rule. First, the IRS reporting requirement will expire after 75 million metric tons of CO_2 is reported as sequestered to IRS, at which point the data collection will end. Second, the level of reporting and transparency would not meet the verification needs of this proposed rule. GS facilities only report the quantity of CO_2 sequestered to IRS. The data used to calculate sequestration and the specific monitoring procedures followed will only be reviewed by IRS staff in the case of an audit. Given the variability in geology and other conditions at GS facilities, EPA believes that the monitoring approach at each GS facility must be reviewed on a case-by-case basis to ensure that it is appropriate for the site-specific geologic and operational conditions. Third, the IRS does not outline procedures or provide a mechanism for quantifying and reporting any CO_2 leakage that may occur as is necessary for this proposed rule.

EPA notes that the United States submits an inventory of GHG emissions that accounts for CCS to the Secretariat of the United Nations Framework Convention on Climate Change (UNFCCC) each year. The UNFCCC, ratified by the United States in 1992, establishes an overall framework for intergovernmental efforts to tackle the challenge posed by climate change. The United States has submitted the Inventory of U.S. Greenhouse Gas Emissions and Sinks (Inventory) to the United Nations every year since 1993. The annual Inventory is consistent with

[11] Available at: http://www.irs.gov/irb/2009-44_IRB/ar11.html.

national inventory data submitted by other UNFCCC parties, and uses internationally accepted methods for its emission estimates. For more information about the Inventory, please refer to the following web site: http://www.epa.gov/climatechange/emissions/usinventoryreport.htm

The United States currently follows the 1996[12] Intergovernmental Panel of Climate Change (IPCC) guidelines in preparing its Inventory, as supplemented by IPCC Good Practice Guidance (GPG) from 2000[13] and 2003[14]. Since these guidelines do not provide information on the accounting of GS, EPA addressed CO_2 usage in the 2007 Inventory by accepting some general, top-down assumptions about the end-use of supplied CO_2. First, EPA collected CO_2 production data for natural CO_2 domes and estimated for each dome the amount of CO_2 used for ER operations and the amount of CO_2 used for non-ER operations. EPA assumed that the percentage of naturally produced CO_2 used for non-ER operations (e.g. food processing, chemical production) was all emitted to the atmosphere. The percentage used for ER operations was assumed to be sequestered. Second, EPA collected data from industry on anthropogenic CO_2 emitted from natural gas processing and ammonia plants and accounted it as emitted, regardless of whether the CO_2 was captured or not.

The IPCC published new inventory guidelines in 2006[15], which directly address accounting for GS and include methodologies for the estimation of emissions from capture, transport, injection, and GS of CO_2. The guidelines are based on the principle that the CCS system should be accounted for in a complete and consistent manner across the entire Inventory. The approach accounts for CO_2 produced from natural CO_2 domes and captured at industrial facilities as well as emissions from capture, transport, and use. For GS specifically, the IPCC guidelines outline a Tier 3 methodology[16] for estimating and reporting emissions based on site-specific evaluations of each storage site. EPA believes that the GS monitoring, reporting, and verification requirements of this proposed rule are consistent with the 2006 IPCC guidelines.

[12] IPCC, 1996. "Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories." National Greenhouse Gas Inventories Programme. Available: http://www.ipcc-nggip.iges.or.jp/public/gl/invs1.html.

[13] IPCC. 2000. "Good Practice Guidance and Uncertainty Management in National Greenhouse Gas Inventories." National Greehouse Gas Inventories Programme. Available at: http://www.ipcc-nggip.iges.or.jp/public/gp/english/.

[14] IPCC. 2003. "Good Practice Guidance for Land Use, Land-Use Change, and Forestry." National Greenhouse Gas Inventories Programme. Available at: http://www.ipcc-nggip.iges.or.jp/public/gpglulucf/gpglulucf.html.

[15] 2006 IPCC Guidelines for National Greenhouse Gas Inventories: Volume 2 – Energy. Chapter 5 Carbon Dioxide Transport, Injection, and Geological Storage. Available at: http://www.ipcc-nggip.iges.or.jp/public/2006gl/index.htm.

[16] Tier 3 methods include either detailed emission models or measurements and data at individual plant level where appropriate.

In considering how to design this proposal, EPA also took into account the monitoring requirements adopted in other countries, in particular other UNFCCC member countries that have already taken steps towards collecting information for CCS to meet the 2006 IPCC guidelines. The Directive of the European Parliament and of the Council on the geological storage of carbon dioxide (Commission decision 2007/589/EC) establishes a legal framework for the environmentally safe geological storage of CO_2. It requires European Council (EC) member states to ensure that each GS site operator will carry out monitoring of the injection facilities, the storage complex (including the CO_2 plume), and, where appropriate, the surrounding environment for detection of any significant migration or leakage of CO_2 or any significant adverse effect on the surrounding environment.

SECTION 3
DEVELOPMENT OF SUBPART RR

Since EPA is proposing that Subpart RR be added to the existing Mandatory Reporting of Greenhouse Gases Program established under 40 CFR 98, we propose that the provisions of 98.1 through 98.6 apply to today's rule unless we describe and provide a rationale for an alternative provision in today's rule. This section describes the development process underlying the proposal of Subpart RR.

3.1 Rule Dimensions for Which Options Were Identified

Possible designs for subpart RR GHG reporting were developed by evaluating options across the following dimensions:

1. Affected Entities

The targeted entities under the Subpart RR source category include:

(1) CO_2 injection facilities, defined as a well or a group of wells that inject CO_2 into the subsurface or sub-seabed geologic formations. This definition would encompass both onshore and offshore facilities.

(2) GS facilities, defined as facilities injecting CO_2 for the purpose of long-term containment in subsurface geologic formations.

2. Thresholds

Upon reviewing the results of a detailed threshold analysis, EPA is proposing that all facilities that meet the definition of this source category must report the data outlined below at no threshold.

3. Data to be reported

All injection facilities must annually report the following:

(a) Mass of CO_2 injected.

(b) Mass CO_2 transferred onsite from offsite

(c) Source of CO_2, if known.

In addition, all GS facilities must annually report the following:

(1) Mass of CO_2 produced, if any.

(2) Mass of CO_2 sequestered in the subsurface geologic formation.

(3) Mass of CO_2 emitted from subsurface leaks, if any.

4. Monitoring, reporting, and verification (MRV) plan requirements

In order to ensure accurate and efficient data reporting, each GS facility must develop a site-specific MRV plan consistent with EPA guidelines.

These dimensions are discussed in more detail below.

3.2 Definition of Affected Entities

1. CO_2 Injection Facility

EPA is proposing that the CO_2 injection facility be defined broadly to cover a well or a group of wells that inject CO_2 into the subsurface or sub-seabed geologic formations. This definition would encompass both onshore and offshore facilities.

EPA is proposing a broad definition of CO_2 injection facility to ensure complete reporting of basic information regarding the quantity of CO_2 transferred onsite, the source of the CO_2 if known, and the amount injected. The broad definition also provides reporters with flexibility either to report this basic information on a well by well basis or to group wells in an area for reporting purposes. Given the proposed threshold and applicability for CO_2 injection facilities, a more specific definition addressing the aggregation of groups of wells in an area is not necessary.

2. GS Facility

EPA is proposing facilities injecting CO_2 for the purpose of long-term containment in subsurface geologic formations would meet the definition of GS in this proposed rule and would report additional information. EPA is proposing that facilities that inject CO_2 for ER would not be GS facilities unless they inject CO_2 for the purpose of long-term containment in subsurface geologic formations and choose to submit and gain EPA approval of an MRV plan.

To comply with the specific reporting requirements detailed in the preamble, the reporter would need to identify the sources and surface equipment making up the GS facility. However, EPA recognizes that defining the extent of a GS facility source may be difficult. For example, there may be a number of injection wells in an oilfield under common ownership or common control of which only a subset would be considered GS facilities. In that example, the question of whether and how to aggregate various wells arises. In addition, the area of review associated with a GS facility may extend for a distance beyond the injection point, and widely separated wells may be injecting into the same pore space. Because EPA is seeking data on the amount of CO_2 sequestered by these facilities and because EPA is proposing an all-in threshold for these facilities, EPA is proposing a narrow definition of GS facility to simplify the reporting requirements associated with emissions from combustion and surface equipment. For purposes of this reporting rule, EPA is proposing to define a GS facility to include all structures associated with the injection of CO_2 located between the points of CO_2 transfer onsite from offsite and the injection well (or wells). A GS facility that injects CO_2 to enhance the recovery of oil or natural gas will also include all structures associated with production located between the production wells and the separators.

Although EPA is proposing a narrow definition of GS facility, the proposed rule would require GS facilities to monitor over a spatial area that will almost certainly extend beyond the boundaries of the facility, as defined here. Given that a main focus of this proposal is to obtain information regarding the efficacy of GS, EPA anticipates that the MRV plans for GS facilities will need to require monitoring over a broad area. This is discussed in the preamble to this rule.

EPA is proposing to exempt research and development (R&D) as defined at 40 CFR Part 98.6 from subpart RR, consistent with the approach taken in subparts C through QQ of the MRR. EPA is also proposing that, for the purposes of GS facility requirements under subpart RR, research and development means those projects receiving Federal funding to research practices and monitoring techniques that will enable safe and effective long-term containment of a gaseous, liquid, or supercritical CO_2 stream in subsurface geologic formations that are neither demonstration nor commercial projects. R&D projects would not be required to submit an MRV plan under subpart RR.

3. Other CO_2 End-Users

In developing this proposed rule, EPA considered requiring reporting from various other end-users of the CO_2 that is produced and supplied to the economy. EPA considered but is not proposing requiring reporting from these other end-users; EPA has concluded that collecting information pursuant to subpart PP on CO_2 supplied to the economy will provide EPA with the necessary data on emissive volumes while minimizing the number of facilities impacted by this rule.

3.3 Selection of Reporting Threshold

To determine the appropriate threshold for reporting under subpart RR, EPA considered both a threshold based on the amount of CO_2 emitted and a threshold based on the amount of CO_2 injected underground. EPA concluded that an emissions-based threshold would be problematic because of the lack of data on the incidence and scale of surface emissions and leakage from injection and GS of facilities. EPA accordingly analyzed injection facilities based on the quantity of CO_2 injected underground and considered whether an injection threshold should apply. EPA evaluated a no threshold option (i.e., all facilities that inject CO_2 would be required to report), 1,000 metric tons per year, 10,000 metric tons per year, 25,000 metric tons per year, and 100,000 metric tons per year per facility of CO_2 injected.

To establish a count of CO_2 injection facilities, EPA relied on data reported in the Oil and Gas Journal (O&GJ) Enhanced Oil Recovery Survey published in April 2008 (Volume 106, Issue 15). EPA compiled all the projects listed for miscible and immiscible CO_2 floods[1] reported in the O&GJ survey. A total of 105 active ER projects were reported. In some cases multiple projects were conducted by the same company in an oil field. For the purposes of this analysis, EPA grouped these reported projects by field and by owner or operator to align with typical industry practices for reporting project information to state oil and gas commissions. This computation results in eighty facilities for the facility count.

The O&GJ survey does not provide the specific volume of CO_2 used in each of the active ER projects. To calculate the estimated volume of CO_2 injected at each ER project, EPA took the total amount of CO_2 used daily for ER, as reported by the U.S. EPA in the Draft 1990 – 2007 Inventory of U.S. Greenhouse Gas Emissions and Sinks,[2] apportioned it to each ER project according to an average value for the fractional production of oil attributed to ER using CO_2 as presented in the O&GJ survey, and normalized the amount of CO_2 injection on an annual basis. The results of the threshold analysis are presented in the preamble to this rule. For further

[1] A miscible CO_2 flood injects CO_2 as a liquid at high pressure to completely mix with oil and make it flow more easily. An immiscible CO_2 flood uses lower pressures of CO_2 to swell the oil and provide additional gas pressure to move the oil.

[2] U.S. EPA Draft Inventory of U.S. Greenhouse Gas Emissions and Sinks, 1990-2007, Draft Report, EPA 430-R-09-004. Available at: http://epa.gov/climatechange/emissions/usinventoryreport.html

information on the assumptions underlying the threshold analysis, please refer to the general technical support document (TSD) for this proposal.[1]

The results of this analysis showed that nearly all injection data can be collected from roughly half of operating facilities at an injection threshold of 100,000 metric tons/yr of CO_2 injected. EPA considered establishing an injection threshold of 100,000 metric tons/yr of CO_2 injected. However, a low CO_2 injection or production quantity in one year is not a reliable prediction of the quantity that may be injected in the following year or in a year of full-scale operation. For example, six of the eighty facilities reported zero or near zero production and therefore did not exceed the 1,000 metric tons threshold. However, these six facilities may inject over this threshold in the following year. In addition, more than 40 of the 105 projects in this analysis were described in the OG&J survey as “just started” or pilot projects, indicating that they may not be at fully operational levels of CO_2 injection. Given the variability of CO_2 injection rates, EPA is proposing that all facilities report irrespective of injection or production quantities in the reporting year.

EPA is proposing that all CO_2 injection facilities would be required to report the minimum information in subpart RR (quantity of CO_2 injected, quantity of CO_2 transferred onsite from offsite, and source of the CO_2 if known) at no threshold. An all-in reporting threshold would allow the Agency to comprehensively track all CO_2 supply (as reported in Suppliers of CO_2, subpart PP) that is injected underground. This approach is consistent with the all-in requirements in the MRR for suppliers of petroleum, natural gas, and coal-to-liquid products (subparts LL, MM, and NN), producers of industrial gases (subpart OO), and suppliers of CO_2 (subpart PP). It was reasonable to require all of the facilities in these source categories to report because it would result in the most comprehensive accounting possible, simplify the rule, and permit facilities to quickly determine whether or not they must report; the same rationale applies for this source category proposed today. Furthermore, it would create a uniform burden for all covered facilities, ensuring a level playing field in, and preventing fragmentation of, the ER sector. EPA has estimated the cost for CO_2 injection facilities to comply with the minimum reporting requirements in this proposed rule and has determined that the burden would be small, given the equipment and data collection efforts already in place at ER projects.

Under this action, EPA is proposing that the subset of CO_2 injection facilities that are conducting GS (i.e. a GS facility) must report to EPA a second tier of data. EPA considered whether a threshold should apply to this second tier of data given that it would place a reporting

[1] Subpart RR General TSD (see docket ID No. EPA-HQ-OAR-2009-0926)

burden on GS facilities. However, EPA could not perform an analysis on GS facilities based on emissions without data on actual or expected GS facility emissions. EPA also could not perform a threshold analysis based on injection due to the uncertainty around predictions of injection quantities for potential GS facilities. In addition, it is difficult to predict how many injection facilities would choose to report GS. Therefore, EPA is proposing to exempt GS R&D projects but otherwise require all GS facilities to comply with the GS monitoring, reporting, and verification requirements of subpart RR, and that they report fugitive, vented, and combustion emissions from surface equipment (under subpart W, RR, or C, as applicable). An all-in threshold will allow EPA to work with the early-movers of this nascent industry and to strengthen EPA's understanding of GS.

3.4 Selection of Data to Be Reported

This section describes the data that injection facilities and GS facilities must report under subpart RR. The first tier of reporting requirements described is for all facilities that inject CO_2 underground. The second tier of reporting requirements described is for GS facilities only.

The first tier has three proposed reporting requirements. First, EPA is proposing that all CO_2 injection facilities report the mass of CO_2 injected. This would be determined by the mass flow or volumetric flow and CO_2 concentration of the CO_2 stream injected. Facilities must use mass flow meters to accurately measure the mass of the CO_2 injected or volumetric flow meters to accurately measure the volumetric flow of the CO_2 injected. To minimize the purchase and installation of new equipment, facilities subject to the UIC program would be allowed to measure the mass or volume of CO_2 injected with the flow meters installed for purposes of compliance with their UIC permits. EPA accordingly is proposing two methodologies for making these calculations, depending on whether the facility is using a volumetric or a mass flow meter. EPA is proposing this approach so that facilities can comply with these reporting requirements regardless of the type of flow meter already installed. In the case of a facility using a volumetric flow meter, EPA assumes that the facility can determine operating temperature and pressure, which would allow for the volumetric flow of CO_2 to be converted from operating conditions to standard conditions and, using a density value for CO_2 at standard conditions and the measured concentration of CO_2 in the flow, determine the mass of CO_2.

Facilities would measure the CO_2 concentration by sampling and testing the injected stream at the flow meter. With this approach, the flow and the concentration would be measured at the same point in the system for maximized data accuracy. Accordingly, if the flow meter were installed at the compressor(s), then the concentration would be measured at the compressor(s). If the flow meter were installed at the well(s), then the concentration would be measured at the well(s). EPA recognizes that a facility with tens or hundreds of injection wells, all of which have flow meters already installed at the wellheads, may face a significant burden in testing concentration at each of those flow meters.

Second, EPA is proposing that all CO_2 injection facilities report the mass of the flow transferred onsite from offsite to verify the mass of CO_2 reported as injected. This would be determined by the mass flow or volumetric flow and CO_2 concentration of the flow transferred onsite from offsite. A subset of CO_2 injection facilities – facilities conducting ER – inject a combination of new CO_2 transferred onsite from offsite and old CO_2 recycled from the operation. Therefore, EPA would use reported data on CO_2 transferred onsite from offsite to estimate the amount of CO_2 recycled from ER operations.

EPA is proposing that all CO_2 injection facilities monitor the CO_2 concentrations and mass flow or volumetric flow quarterly. The purpose of these measurements is to account for fluctuations in the CO_2 concentration over the reporting year.

Third, EPA is proposing that all CO_2 injection facilities would report the source contracted to supply the CO_2, if known. EPA would seek information on whether the CO_2 was contracted from a natural source (i.e. produced from a natural CO_2 dome) or an industrial source. If an industrial source, EPA would seek information on the type of source if known (captured at a power plant, pulp and paper mill, ethanol plant, natural gas processing facility, or other type of industrial source). This would allow EPA to track the movement of CO_2 through a CCS system and any shift toward anthropogenic CO_2 supply sources. Pipelines that carry CO_2 to the CO_2 injection facility may contain a mix of CO_2 from various sources. EPA recognizes that facilities may not know the source of CO_2 that they purchase. Accordingly, EPA would require the data to be reported only if known.

EPA recognizes that at this time the source of CO_2 injected underground is predominantly CO_2 produced from natural CO_2 domes. It is possible that GS using naturally sourced CO_2 may not qualify as a GHG mitigation action because the purpose of GS is to isolate CO_2 that would otherwise have been emitted to the atmosphere. Under this proposed rule, however, GS facilities must report annual CO_2 sequestered regardless of the source.

For this proposed rule, EPA also considered, but is not proposing, that a CO_2 injection facility be required to report only the CO_2 injection data it collects under its current UIC permit (under any class) or relevant permit in the case of a facility that is outside SDWA jurisdiction.

Although this would impose the lowest burden on the reporter since no new data would need to be collected, EPA would not receive complete data on the mass of CO_2 injected. While collection of injection volume is a minimum monitoring requirement for all UIC well classes, CO_2 concentration data are not. Furthermore, facilities are not required to report CO_2 transferred onsite from offsite sources or the source of CO_2 under any UIC permit class.

EPA is proposing that GS facilities would report a second tier of data in subpart RR. These reporting requirements include the amount of leakage of CO_2 to the surface (if any), the amount of CO_2 in produced oil or gas (for GS facilities conducting active ER operations), the amount of fugitive and vented CO_2 emissions from surface equipment, and the total annual amount of CO_2 sequestered using a mass balance equation. In this equation, the sum of the CO_2 emissions listed above would be subtracted from the amount of CO_2 injected to equal the amount of CO_2 sequestered. These four reporting requirements are described in more detail below.

GS facilities must report CO_2 leakage, if any occurs from the subsurface geologic formation to the surface. EPA is not proposing specific procedures or methodologies for detecting or quantifying CO_2 leakage. However, each GS facility would be required to develop and implement a site-specific approach to monitoring, detecting, and quantifying CO_2 leakage based on requirements that are outlined in detail in the preamble to this rule.

First, EPA is proposing that GS facilities that are actively producing oil or gas would be required to report the quantity of CO_2 produced out of the subsurface with produced oil or natural gas. This would be done by measuring at each separator the volumetric flow or mass flow and the concentration of a CO_2 stream. These GS facilities would also report CO_2 that remains in the oil or gas after separation.

Second, unless already reported in the petroleum and natural gas system subpart, subpart W, EPA is proposing that all GS facilities would be required to report fugitive and vented CO_2 emissions from surface components located within the facility for which procedures and methodologies are provided in subpart W. This could include pump blow-downs and fugitive emissions from valves, flanges, and compressors. EPA seeks these data to better understand the volume of fugitive and vented GHG emissions at GS facilities as compared to the volume of CO_2 sequestered. This information is an important indicator of the effectiveness of GS as a GHG mitigation technology. In addition, fugitive and vented CO_2 emissions will need to be included in the mass balance calculation of GS if they occur downstream of the CO_2 injection flow meter or (if applicable for ER projects) upstream of the production flow meter. This proposed rule does not impose a general requirement for all CO_2 injection facilities to report fugitive and vented CO_2 emissions from surface components since facilities that are not sequestering CO_2 would not report GS.

Lastly, EPA is proposing that GS facilities use a mass balance equation to calculate and report CO_2 sequestered in the subsurface geologic formation in the reporting year. This reported data point would be valuable for EPA as the Agency tracks CO_2 across a CCS system and will provide EPA with information on the performance of GS projects over time. Alternatively, EPA could approximate CO_2 sequestered in the subsurface without proposing additional reporting requirements for GS facilities, by using data already reported on CO_2 transferred from offsite and CO_2 injected. EPA considered but did not propose this approach because it does not account for potential leakage from the subsurface and does not properly account for CO_2 fugitive or vented emissions from surface equipment during post-production, processing, transport, or compression. Given the importance of GS as a GHG mitigation technology, EPA seeks to achieve an accurate reporting of GS.

EPA recommends that CO_2 injection and GS facilities review subparts C and PP and proposed subpart W. Subpart C provides GHG calculation procedures and reporting requirements for stationary fuel combustion devices that combust solid, liquid, or gaseous fuel. CO_2 injection and GS facilities should pay close attention to compressors and pumps located within the facility boundary. Subpart PP provides procedures for calculating and reporting quantities of CO_2 supplied to the economy. The Subpart W proposal covers petroleum and natural gas systems by defining eight types of facilities and providing calculation procedures and reporting requirements for the GHG emissions of specific equipment that may be located in those facilities. CO_2 injection and GS facilities should review in particular the definitions of onshore and offshore petroleum and natural gas production facilities.

EPA is proposing that if an injection facility is not conducting GS, it would determine applicability to other subparts of the rule separately from applicability to subpart RR. This is similar to the approach taken by reporters of upstream petroleum products supply, natural gas supply, natural gas liquids supply, and carbon dioxide supply (reporters in subparts MM, NN, and PP). For example, an injection facility not characterized as a GS facility would not automatically trigger reporting under subpart C by this proposal, but would make a separate applicability determination under subpart C. A GS facility would automatically trigger applicability under other subparts of the rule. This is similar to the approach taken by reporters of downstream emissions in the rest of the MRR. For example, the GS facility would report under subpart C the emissions from combustion sources located within the facility boundary, such as compressors.

In selecting data to be reported under today's proposal, EPA compared reporting requirements under today's subpart RR proposal with reporting under the UIC Class VI proposal. EPA found two data elements with potential overlap. The first area of potential overlap is the reporting of the amount (flow rate) of injected CO_2. The UIC Class VI and subpart RR proposals differ in the measurement unit and collection/reporting frequency. EPA determined that reporting of the amount (flow rate) of injected CO_2 was necessary in order to harmonize the data with other subparts of the MRR. To ensure that data needs are harmonized between the MRR and the UIC program requirements and to reduce burden, and because this data under a state-issued UIC permit is currently submitted to states while, under today's subpart RR proposal, reporters will be submitting data directly to EPA.

The second area of potential overlap relates to monitoring plans. Although both the UIC Class VI proposal and today's subpart RR proposal have monitoring plan requirements, the UIC Class VI proposal is focused on protection of USDWs, while today's subpart RR proposal is focused on air emissions. Potential differences include baseline data and detection and measurement of CO_2 leakage to the surface. Recognizing that air monitoring under the UIC Class VI proposal is at the discretion of the UIC director, EPA notes that a UIC Class VI permit may fulfill requirements under today's proposal.

EPA considered whether a GS facility should also report methane (CH_4) leakage emissions from the subsurface. CH_4 emissions from the subsurface may occur at oil and natural gas reservoirs or ECBM sites. The cases in which leakage of CH_4 could occur at these sites may be similar to the potential for CO_2 leakage. CH_4 leakage could potentially occur through improperly sealed wells, open faults, and other pathways that have also been identified as potential CO_2 leakage pathways. However, CH_4 is present as a gas, and thus may be more upwardly mobile than CO_2 which is injected as a supercritical fluid. Therefore, the potential for leakage of methane at depleted oil and gas or ECBM sites may be greater than for $CO_{2.}$

EPA is proposing to focus on CO_2 emissions. EPA recognizes the potential for CH_4 leakage from the subsurface at facilities conducting GS in oil and gas reservoirs or coal seams and therefore seeks comment on whether to require reporting on CH_4 leakage. If the potential for CH_4 leakage exists, the GS reporter could include in the MRV plan a monitoring strategy to detect and quantify potential CH_4 leakage. CH_4 fugitive and vented emissions from surface equipment are covered under the proposed oil and gas subpart, subpart W.

Under subparts C through QQ of the MRR, adjacent or contiguous equipment in actual physical contact under common ownership or common control constitute a facility (see Section

98.6 of the MRR). In the case of petroleum and natural gas systems and GS, equipment are not necessarily in physical contact with one another in the conventional sense of the term. Subparts W and RR are each proposing interpretations of what would constitute a facility. As a result, a GS facility conducting ER may apply one facility boundary for reporting under subpart W and a different facility boundary for reporting under subpart RR. EPA acknowledges that this may present a challenge for submitting annual reports, depending on how the data system is designed. A CO_2 injection or GS operation would submit an annual report to EPA according to the proposed definition of facility.

EPA also recognizes that, in the case of an ER operation conducting GS, the combustion emissions from equipment within the GS facility would be included in both annual reports. Though this approach results in duplicative reporting, EPA has concluded that to analyze the efficacy of GS as a GHG mitigation tool, EPA needs to collect information on combustion emissions from GS facility equipment at only the GS facility level rather than aggregated with emissions from additional equipment.

3.5 Selection of proposed monitoring, reporting, and verification (MRV) plan requirements and approval process

3.5.1 Selection of MRV Plan Option

EPA considered three alternatives for monitoring, reporting and verification of potential CO_2 leakage at GS sites: do not require an MRV plan, require a universal MRV plan that applies to all GS sites, or require a site-specific MRV plan. The three alternatives vary in stringency and specificity as described below. EPA outlines the advantages and disadvantages of each alternative and seeks comment on each alternative, as well as any alternatives not discussed.

Under the first alternative, EPA would allow GS facilities to report the amount of CO_2 sequestered without requiring an MRV plan. Under this alternative, the Agency would rely on published information and existing studies to assume that injected CO_2 remains sequestered and would assume these results can be generalized to all GS projects. This alternative would impose the least burden on reporters. EPA notes that international guidelines on information collection and reporting efforts do not support this approach. Furthermore, EPA did not propose this approach because of the limited empirical data and the variability in geology and other conditions among GS facilities.

The second alternative that EPA considered was a one-size-fits-all MRV plan approach under which the Agency would prescribe specific monitoring technologies and quantification methods for GS facilities. The advantage of this approach is that all GS facilities would use the same monitoring technologies and methods. The disadvantage of this approach is that the geology and other conditions at potential GS facilities will vary from site to site and a one-size-fits all approach may not provide the most effective monitoring strategy for all facilities. EPA notes that international guidelines on information collection and reporting efforts do not support this approach. In addition, since the monitoring and testing plans implemented under the UIC program are necessarily site-specific in nature, it would be difficult to prescribe a one-size-fits-all MRV plan that would complement and build upon the UIC program. This alternative would likely be the least cost effective and most burdensome approach for reporters.

The third alternative, and the alternative that EPA is proposing, is that GS facilities be required to develop a site-specific MRV plan and submit it to EPA for approval. Facilities would report CO_2 injection until the final MRV plan has been approved. Once a final MRV plan has been approved by EPA, GS facilities would implement the plan, including the reporting of the amount of CO_2 that has been sequestered. The advantage of this approach is that it provides a flexible and cost-effective option for reporters and complements monitoring requirements under the proposed UIC Class VI rule. EPA recognizes that the rigorous proposed UIC Class VI requirements will provide the foundation for the safe sequestration of CO_2 and should serve to reduce the risk of CO_2 leakage to the atmosphere when finalized. An adequate MRV plan would be tailored to site-specific conditions and be designed for each stage of the GS project. In addition, the MRV plan would allow for modification or adaptation of the plan based on monitoring results. Although the risk of leakage at an appropriately selected and managed GS facility may be low, the MRV plan would ensure that if leakage occurs, the GS reporter would have an approved methodology for measuring the emitted CO_2. If leakage occurs, the MRV plan would also provide a process for revising the MRV plan if necessary.

It is important to recognize that this proposed rule is a data collection and monitoring proposal which does not directly address the potential human health and welfare, ground or surface water, ecosystem or geosphere impacts of GS. Therefore, the proposed rule does not address these potential impacts from CO_2 leakage (e.g. requiring remediation or mitigation) as this is outside the scope of this proposal.

EPA is proposing that each submitted MRV plan must include at a minimum the four requirements described below:

Step 1 – Assessment of Risk of Leakage: All potential pathways that may result in CO2 leakage have been identified and characterized and the risk of CO2 leakage at each pathway has been evaluated;

Step 2 – Strategy for Detecting and Quantifying CO2 Leakage to Surface: Potential pathways will be monitored according to the risk of CO2 leakage to ensure that any leakage to the surface will be detected and that leakage to the surface, should it occur, will be quantified according to a specified methodology;

Step 3 - Strategy for Establishing Pre-Injection Environmental Baselines: Environmental baselines against which the monitoring results will be evaluated have been established at potential leakage pathways; and

Step 4 - Tailor Mass Balance Equation: Site-specific variables have been considered and developed for the mass balance equation provided in the regulatory text to calculate the amount of CO2 sequestered.

Details regarding MRV requirements are provided by EPA in the preamble to this rule. EPA also developed a monitoring plan technical support document that describes characteristics of a robust monitoring plan.[1]

3.5.2 Background on MRV Approaches

EPA has identified published studies and/or guidelines on monitoring programs that identify and quantify CO_2 leakage from GS facilities.[2] While the science of quantifying CO_2 leakage from GS facilities is evolving, it is generally recognized that, when properly planned and implemented, monitoring methods will be effective at detecting leakages.[3,4]

Though the methodologies for detecting and quantifying leakage of CO_2 from GS facilities have not been standardized, EPA has concluded that a GS facility would be able to propose a site-specific plan for leak detection and quantification under this rule based on the current availability of monitoring technologies. A wide range of techniques for monitoring

[1] Monitoring Plans for Geologic Sequestration TSD (see docket ID No. EPA-HQ-OAR-2009-0926)

[2] Arts, R, O Eiken, A Chadwick, P Zweigel, L van der Meer, B Zinszner. 2004. “Monitoring of CO2 injected at Sleipner using time-lapse seismic data.” Energy 29: 1383-1392; Wilson, M. and M. Monea (Eds.). 2004. “IEA GHG CO2 Weyburn CO2 Monitoring and Storage Project,” Seventh International Conference on Greenhouse Gas Control Technologies, Vol. 3; Klusman, RW. 2003. “Rate Measurements and Detection of Gas Microseepage to the Atmosphere from an Enhanced Recovery Sequestration Project, Rangely, Colorado, USA,” Applied Geochemistry, 18, 1825-1838; IPCC. 2006. “2006 IPCC Guidelines for Greenhouse Gas Inventories.” Intergovernmental Panel on Climate Change, Simon Eggleston, ed. http://www.ipcc-nggip.iges.or.jp/public/2006gl/index.html; DOE/NETL. 2009. “Best Practices for Monitoring, Verification, and Accounting for CO2 Stored in Deep Geologic Formations.” U.S. Department of Energy, National Energy Technology Laboratory.

[3] Benson, SM. 2006. “Monitoring Carbon Dioxide Sequestration in Deep Geological Formations for Inventory Verification and Carbon Credits.” Society of Petroleum Engineers Paper 102833.

[4] FutureGen Alliance. 2006. “Mattoon Site Environmental Information Volume.” December 2006.

sequestration of CO_2 have been used for a number of years in other applications, including oil and natural gas production, natural gas storage, disposal of liquid and hazardous waste in deep geologic formations, groundwater monitoring, and ecosystem research.[1] Some monitoring techniques such as seismic monitoring can detect the presence and location of CO_2 in the subsurface, including both vertical and lateral spread, although the accuracy of seismic monitoring for quantifying the amount of CO_2 may be more limited than other approaches. Other techniques, such as soil gas monitors or eddy covariance techniques, can detect, within a certain limit, leakage of CO_2 from the confining system. Many of these technologies have excellent sensitivity, and have been shown to be able to detect relatively low concentrations of CO_2 above background levels. The minimum leakage rate detectable is a function of parameters such as the volume of CO_2 making its way to the surface, the size of the leak area, and the sensitivity of the monitoring device.

Descriptions of the various monitoring technologies that could be deployed at a GS facility can be found in the general TSD to this proposal[2]. Additional information on GS monitoring technologies can also be found in the IPCC Guidelines for National Greenhouse Gas Inventories (2006), the API/IPECA Inventory Guidelines for CCS (2007), Department of Energy MVA Best Practices Manual (2009), and the International Energy Agency GHG R&D Programme monitoring tool website (www.co2captureandstorage.info/co2monitoringtool).

3.6 Selected Option

The selected approach is tiered. First, a set of reporting requirements is proposed to cover all facilities that inject CO_2 underground regardless of the purpose of injection. A subset of facilities that inject CO_2 and conduct geologic sequestration (GS) have additional requirements and include developing and implementing a Monitoring, Reporting, and Verification (MRV) plan which, once approved by EPA, would be used to verify injected CO_2 as sequestered and to quantify emissions in the event that injected CO_2 leaks, or is suspected of leaking, to the surface.

Since the geology and conditions at each GS facility will vary widely, EPA proposes a case-by-case MRV plan approval process. EPA will evaluate each MRV plan to ensure that the GS facility has an appropriate strategy in place to effectively quantify geologically sequestered

[1] Benson, S and L Myer. 2002. “Monitoring to Ensure Safe and Effective Geological Sequestration of Carbon Dioxide.” Lawrence Berkeley Laboratory, Berkeley, California; Benson, SM. 2002. "Geologic Sequestration of Carbon Dioxide." The Carbon Dioxide Dilemma, Promising Technologies and Policies, Proceedings of a Symposium, National Academy of Engineering, April 23-24, 2002, Washington, D.C., pp. 29-39.

[2] Subpart RR General TSD (see docket ID No. EPA-HQ-OAR-2009-0926)

CO_2. EPA will evaluate the adequacy of the methodologies proposed to detect and quantify leakage, including whether the chosen monitoring technologies are suitable for the type of leakage pathway and for the type of risk evaluated at that pathway.

Although MRV plan approval would be an inherently EPA function, the Agency is considering approaches and processes to streamline and facilitate external technical input in the development of specific evaluation criteria or guidelines, particularly at the outset of the program. EPA recognizes that an adaptive approach to the GS portion of this proposal will be necessary to take advantage of the experience gained in developing and implementing MRV plans and in complying with the proposed UIC Class VI requirements. EPA expects to update the guidelines and requirements of an MRV plan over time as technologies, methodologies, and scientific understanding of GS evolve; and the Agency believes that the site-specific nature of the MRV plan enables the proposed approach to adapt and improve over time.

3.7 Alternative Scenarios Evaluated

Given uncertainties related to project adoption and the costs of the reporting program. EPA currently considered two other costs scenarios (one requires higher levels of monitoring and the other requires lower levels of monitoring relative to the reference cost scenario) in order to assess a range of cost estimates and economic impacts on affected entities. The monitoring options vary by which monitoring devices would be used at a GS site and how often sampling and measurement would take place. Second, it is currently unknown how many projects conducting ER would choose to meet the definition of a GS facility and submit an MRV plan. As a result, three potential scenarios of the quantity of facilities that would convert have been considered in the economic impact analysis to represent low, medium, and high outcomes. Finally, EPA considered two additional scenarios of the quantity of saline formation GS project outcomes in the economic impact analysis to represent lower and higher outcomes.

3.8 Data Quality

For this analysis, EPA gathered existing data from EPA, industry trade associations, states, and publicly available data sources (e.g., labor rates from the Bureau of Labor Statistics [BLS]) to characterize the processes, sources, sectors, facilities, and companies/entities affected. Costs were estimated based on the data collected and engineering analysis and models provided by EPA and its contractors. EPA staff and contractors provided engineering expertise, knowledge of existing facility conditions and activities (e.g., typical labor hours required for developing QA plans and performing CO_2 stream sampling), and an estimate of incremental activities required to comply with the rule.

The most important elements affecting the data quality for this analysis include the number of affected facilities in the source category, the site by site variability of GS sites, process inputs and outputs (especially for monitoring procedures that involve a carbon mass balance), and the measurements that are already being made for reasons not associated with the rule (to allow only the incremental costs to be estimated). The background information was supplemented from numerous sources, including industry surveys from the U.S. Census Bureau, trade associations, and operating permits, for example. Information on measurements that are already made (and thus would not be associated with the rule) was obtained from discussions with industry representatives, knowledge gained from previous site visits, and other sources. The data collected to characterize the facilities in this source category are judged to be of good quality and the best that is publicly available. Other elements affecting the quality of the data include estimates of labor hours to perform specific activities, cost of labor, and cost of monitoring equipment. Estimates of labor hours were based on previous analyses of the costs of monitoring, reporting, and recordkeeping for other rules; information from the industry characterization on the number of units or process inputs and outputs to be monitored and engineering judgment. Labor costs were taken from the BLS and adjusted to account for overhead. Monitoring costs were generally based on cost algorithms or approaches that had been previously developed, reviewed, accepted as adequate, and used specifically to estimate the costs associated with various types of measurements and monitoring. The data quality associated with these elements of the cost analysis is analogous to the quality of data used in the development of numerous other Information Collection Requests for the different industrial source categories.

SECTION 4
ENGINEERING COST ANALYSIS

4.1 Introduction

Using available industry and EPA data to characterize conditions at affected sources, EPA estimated the costs of complying with this proposed rule. Incremental monitoring, recordkeeping, and reporting activities were then identified for each type of facility, and the associated costs were estimated.

4.2 Overview of Cost Analysis

The costs of complying with the rule will vary from one facility to another, depending on the nature of the CO_2 injection activities (GS or non-GS), the MRV plan selected, existing monitoring, recordkeeping, and reporting activities at the facility, etc. The costs include labor costs for performing the monitoring, recordkeeping, and reporting activities necessary to comply with the rule, as well as capital costs related to the implementation of monitoring activities outlined in the MRV plan for GS sites. All costs referred to in this section are reported in 2008 dollars.

We first provide a general overview of baseline reporting and GS activities. This is followed by detail on the cost components associated with this information collection; labor costs (i.e., the cost of labor by facility staff to meet the information collection requirements of the rule); and capital and operating and maintenance costs (e.g., the cost of purchasing and installing monitoring equipment or contractor costs associated with providing the required information).

4.3 Baseline Reporting

4.3.1 Introduction

The Environmental Protection Agency is developing a set of proposed regulatory alternatives for reporting of CO_2 injection and GS. These rules can affect the number and type of monitoring equipment installed at the sites and the type and frequency of tests and surveys conducted at the sites. In creating new EPA regulations, a unit cost analysis and the total cost impact of each of the proposed regulations is required by federal law. This provides a basis for a full evaluation of the incremental costs of the proposed rule. The purpose of this section is to present the "activity baseline," which describes the number and types of injection and GS sites that could be subject to the rule and the volume of CO_2 injections that would be expected.

Through the practice of geological sequestration, CO_2 can potentially be sequestered in underground formations worldwide for thousands of years. Although commercial geologic sequestration of CO_2 has not yet begun in the U.S., several projects such as Sleipner in the North Sea, In Salah in Algeria, and Weyburn in Alberta have achieved success in recent years. CO_2 at these sites is being sequestered, and technologies to monitor the process have proved effective. In the U.S., the Department of Energy is supporting approximately 25 sequestration pilot projects around the country. DOE also has plans to start a number of relatively large scale pilot projects within coming years.

Geologic sequestration in the U.S. will likely occur in a range of different geologic settings including: saline reservoirs, oil and gas reservoirs, coal seams, and others. For purposes of this economic analysis, the costs of specific aspects of geologic sequestration were specified on the basis of cost per well, per square mile, per sample, or other basis for each project. In addition, "type cases" were developed for each reservoir type including, in some instances, two sizes of injection projects for pilot and commercial-size project scales. These include the typical parameters (e.g. number of monitoring wells and average well depth) for each type of project, allowing for estimation of total cost per project. In the cost analysis that appears in Chapter 5, a base case is created assuming relevant monitoring costs are only that which is required under the UIC rules. Then three regulatory alternatives for reporting from geologic sequestration sites are evaluated in terms of technologies and practices and their costs.

4.3.2 *Data Sources*

In order to evaluate the total costs in the U.S. of the proposed regulations, it is necessary to establish an activity baseline forecast of the sequestration activity to which the proposed regulation applies. The appropriate forecast for this analysis is the level of GS activity that would be expected even in the absence of future climate change legislation. While climate change legislation is currently being debated in Congress, no legislation has been enacted. Even in the absence of national climate legislation, sequestration activity in the U.S. is planned including:

- Research and Development (R&D) projects,
- FutureGen Sequestration Site, and
- Commercial Sequestration Projects Related to State and Regional Incentive Programs (in part, funded by DOE)

4.3.3 *Published Data on CO_2 Sequestration Projects*

4.3.3.1 Planned R&D Projects

The Department of Energy has funded an extensive research effort into geologic sequestration in the U.S. The project is a collaborative effort with seven regional partnerships. The research effort is managed by the National Energy Technology Laboratory in Morgantown, West Virginia. The program has two major components: Core R&D and Demonstration and Deployment.

According to DOE, the goal is to “develop by 2012 systems that will achieve 90% capture of CO_2 at less than a 10 percent increase in the cost of energy services and retain 99 percent sequestration permanence.” [26]

The field component of the sequestration research is being carried out by seven regional partnerships. These partnerships were formed in 2003 and represent consortia of private industry and government agencies. This effort is tasked with determining the most suitable technologies, regulations, and infrastructure needs for capture and sequestration.

There are three phases to the work being carried out by the partnerships:

- Characterization (2003-2005)

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[26] *Direct Carbon Sequestration: Capturing and Storing Carbon Dioxide*, Congressional Research Service, report RL33801, September, 2007.

- Validation (2005-2009)
- Deployment (2009-2017)

The Characterization Phase involved the geologic analysis that resulted in the development of a National Carbon Sequestration Database and Geographic Information System (NATCARB). The Validation Phase is currently active and involves such activities as validation of reservoir simulation methods, data collection for capacity and injectivity, and demonstration of monitoring technologies. Also being researched are well completion methods, operations, and abandonment approaches.

The Deployment Stage involves the construction and operation of 8 significant sequestration projects. These projects are consistent with the Energy Independence and Security Act of 2007 (EISA), under Title VII, Sec. 702, which requires DOE to conduct at least 7 large scale sequestration field tests greater than one million tons of CO_2 each. These tests are designed to fully evaluate the potential for commercial scale operations in a range of geological settings. The tests are planned to have an injection period of up to four, followed by a lengthy monitoring period. This phase is designed to evaluate the practical aspects of large scale injection over a prolonged period of time.

A great deal of progress has been made in the areas of site characterization and monitoring. The next major phase of the DOE research effort is to provide funding support for a number of commercial scale sequestration operations with injections of up to one million tons per year.

<u>Sequestration Related to State and Regional Incentive Programs</u>

A number of states or regions have adopted or plan to adopt regulations to address carbon dioxide and/or greenhouse gas emissions. Most allow for regulated sources of emissions to meet compliance requirements through the use of offsets. Although geologic sequestration goals or criteria may not be specified in each case, the potential exists for sequestration activities to become an accepted and more prevalent way of meeting greenhouse gas reductions.

The programs or state legislation initiatives are generally in the early stages, and there is considerable uncertainty in terms of which projects will proceed, and on what schedule. ICF has researched the CSLF (Carbon Sequestration Leadership Forum) online database and the MIT online database in our analysis of non-DOE projects. It should be noted, that in these databases, there are several projects for which startup date and/ or planned injection volumes are not specified.

Laboratory Research

Over the past several years, DOE and the regional partnerships have carried out an effort to assess and characterize the CO_2 sequestration capacity and potential of the U.S. This effort has resulted in the publication of a large amount of information on potential by geologic setting and basin or state. A large amount of GIS data has also been compiled on the geology of sequestration potential.

In 2008, DOE published the most recent version of the NATCARB (National Carbon) Atlas. [27] This publication contains maps and data tables documenting their assessment of sequestration potential in the U.S. Much of the data behind the NATCARB atlas are either available in GIS form or will eventually be made available.

4.3.4 Hydrogeologic Settings

Geologic sequestration may take place in a number of settings and lithologies. These include:

- Non-basalt saline reservoirs
- Depleted gas fields
- Depleted and abandoned oil fields
- Enhanced oil recovery (ER)
- Enhanced coalbed methane recovery

For the purposes of analyzing the GS rule, we will focus on the settings that are most likely affected by the rule, which includes saline reservoirs and oil and gas fields.

4.3.4.1 Non-Basalt Saline Reservoirs

Most significant sedimentary basins in the U.S. contain regionally significant saline formations that are potential sequestration reservoirs. These are typically sandstone lithologies with good porosity, containing formation waters of greater than 10,000 mg/L total dissolved

[27] *Carbon Sequestration Atlas of the United States and Canada*, 2008, U.S. Department of Energy, National Energy Technology Laboratory, Morgantown, WV.

solids. Salinity may be as high as several times that of seawater. Thus, the water is unsuitable for drinking or agriculture. Saline reservoirs dominate the assessed potential of the U.S. and worldwide. In addition, because of their wide geographic distribution in the U.S., saline reservoirs are often in close proximity to CO_2 sources, minimizing pipeline transport distance. Saline reservoirs represent the vast majority of U.S. sequestration potential (approximately 89 percent of total U.S. capacity). [28] It is very likely that saline reservoirs will play a prominent role in future geologic sequestration.

Sequestration in saline reservoirs has been shown to be effective. The Sleipner field in the North Sea is the first commercial-scale saline reservoir project. Carbon dioxide is separated from the gas stream and re-injected into a reservoir at about 800 meters depth. The rate of injection is 2,700 tons per day or about one million tons per year. [29] It is anticipated that about 20 million tons will eventually be stored. At Sleipner, the plume has been monitored effectively. [30]

DOE has extensively studied saline reservoirs for sequestration. Projects include the Frio Brine pilot in the Texas Gulf Coast and the Mount Simon Sandstone in the Illinois Basin. [31] The Mount Simon is known to have excellent sequestration potential because of its regional thickness and reservoir characteristics, and because it has been used extensively for natural gas sequestration in the Midwest.

4.3.4.2 Depleted Gas Fields and Oil Fields

Depleted gas and oil fields can be excellent candidates for CO_2 sequestration. These represent known structures that have trapped hydrocarbons over geologic time, thus proving the presence of an effective structure and seal above the reservoir. These fields have also been extensively studied, there is a large amount of well log and other data available, and the field infrastructure is already in place. This infrastructure could in some cases be utilized in sequestration. A potentially problematic aspect of using depleted fields for sequestration is the

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[28] 2007 ICF assessment developed using DOE Atlas volumes and supplementing in several categories.

[29] *IPCC, 2005: IPCC Special Report on Carbon Dioxide Capture and Storage,* by Working Group III of the Intergovernmental Panel on Climate Change [B. Metz, O. Davidson, H. C. de Coninck, M. Loos, and L. A. Meyer (eds.)], Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA, 442 pp.

[30] *IPCC, 2005: IPCC Special Report on Carbon Dioxide Capture and Storage,* by Working Group III of the Intergovernmental Panel on Climate Change [B. Metz, O. Davidson, H. C. de Coninck, M. Loos, and L. A. Meyer (eds.)], Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA, 442 pp.

[31] *Carbon Capture and Storage: A Regulatory Framework for States – Summary of Recommendations,, by Kevin Bliss,* Interstate Oil and Gas Compact Commission, January, 2005.

presence of a large number of existing wellbores, which can provide leakage pathways. Typically, oil fields are developed with a closer spacing than gas fields, resulting in a larger number of existing wells per unit area than in gas fields.

The In Salah Field in Algeria was the world's first project in which CO_2 is injected at commercial scale into a gas reservoir. However, in this case, the gas is injected downdip in an actively producing gas reservoir. This differs from an abandoned gas reservoir scenario in which the gas field is no longer producing.

4.3.4.3 Enhanced Recovery of Oil and Gas

Under certain reservoir and fluid conditions, CO_2 can be injected into an oil reservoir in a process called miscible CO_2 enhanced oil recovery. The effect of the CO_2 is to mobilize the oil so that it can move more readily to the production wells. As the oil is produced, part of the injected CO_2 is produced with the oil. This CO_2 is then separated and re-injected.

In the U.S. most CO_2 ER projects are located in the Permian Basin of West Texas, where projects have been in place for several decades. The source of most of the CO_2 is natural CO_2 from several fields in Colorado and New Mexico. [32] Some of the injected CO_2 is from gas processing or other sources. The current volume of CO_2 injected for CO_2 ER is about 2.2 billion cubic feet per day.

In 2005, CO_2 ER operations produced approximately 237,000 barrels of oil per day in the U.S. About 180,000 barrels per day of that occurred in West Texas, with most of the rest produced in the Rockies, Mid-Continent, and Gulf Coast. [33]

The development of CO_2 ER projects has resulted in a great deal of knowledge about the process and injection well and other technologies have matured and are well understood. In addition, it is estimated that more than 3,500 miles of high pressure (>1,300 psi) CO_2 pipelines have been built to accommodate these operations. [34]

At the Weyburn Field in Saskatchewan, CO_2 from the Dakota Gasification Facility in North Dakota is injected into an oil reservoir for ER and monitoring of CO_2 sequestration. Over

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[32] *The Economics of CO_2 Storage*, Gemma Heddle, Howard Herzog, and Michael Klett, Laboratory for Energy and the Environment, Massachusetts Institute of Technology, August, 2003.
[33] Oil and Gas Journal, April 17, 2006.
[34] *Carbon Capture and Storage: A Regulatory Framework for States – Summary of Recommendations,, by Kevin Bliss,* Interstate Oil and Gas Compact Commission, January, 2005.

the 25 year life of this project, it is expected that about 18 million tons of CO_2 will be sequestered.

4.3.4.4 Enhanced Coalbed Methane Recovery

CO_2 can potentially be sequestered in coalbeds through the process of adsorption. CO_2 injected as a gas into a coal bed will adsorb onto the molecular structure and be sequestered.

Methane is naturally adsorbed onto coalbeds and coalbed methane now represents a significant percentage of U.S. natural gas production. Major coalbed methane production areas include the San Juan Basin of northwestern New Mexico and southwestern Colorado, the Powder River Basin of eastern Wyoming, and the Warrior Basin in Alabama.

The concept of enhanced coalbed methane recovery is based upon the fact that coalbeds have a greater affinity for CO_2 than methane. Thus, when CO_2 is injected into the seam, methane is liberated and the CO_2 is retained. This additional methane represents enhanced gas recovery.

Depending upon depth and other factors, coalbeds may be mineable or unmineable. Because the process of mining the coal would release any stored CO_2, only unmineable coals are assessed as representing permanent CO_2 sequestration. [35]

4.3.4.5 Other Hydrogeologic Settings

Basalt flows such as those of the Columbia River Basalts in the Pacific West, are believed to have the potential for permanent CO_2 sequestration. The sequestration process is geochemical trapping, in which the CO_2 reacts with silicates in the basalt to form carbonate minerals. [36] While research is being carried out on basalt, it is considered unlikely that any commercial scale sequestration will occur in the foreseeable future due to the unconventional geology and likely difficulty in monitoring.

The potential to sequester CO_2 in organic shale formations is based upon the same concept as that of coal beds. CO_2 will adsorb onto the organic material, displacing methane. Gas shales have recently emerged as a major current and future source of gas production in the U.S. These include the Barnett Shale in the Fort Worth Basin, the Fayetteville and Woodford

[35] *Carbon Capture and Storage: A Regulatory Framework for States – Summary of Recommendations,, by Kevin Bliss*, Interstate Oil and Gas Compact Commission, January, 2005.

[36] *IPCC, 2005: IPCC Special Report on Carbon Dioxide Capture and Storage*, by Working Group III of the Intergovernmental Panel on Climate Change [B. Metz, O. Davidson, H. C. de Coninck, M. Loos, and L. A. Meyer (eds.)], Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA, 442 pp.

Shales in the Arkoma Basin, and the Appalachian Devonian Shale. These Devonian and Mississippian age organic shale formations represent tremendously large volumes of rock. To date little research has been done on enhanced gas recovery with organic shales. However, should it prove technically feasible, the U.S. could become one of the major areas worldwide for this type of sequestration.

4.3.5 Formation Capacity

4.3.5.1 Current DOE Assessment of Sequestration Potential

Through the regional sequestration partnerships, DOE has developed a new national assessment of sequestration potential. The current assessment is summarized in Table 4-3, in the column titled "2008 NATCARB." As evaluated by ICF, the DOE Lower-48 total is 8,179 gigatonnes (Gt) of CO_2. The range of uncertainy is 3,508 to 12,850 Gt. Most of the assessment is attributed to saline reservoirs). This assessment is much larger than the prior assessments also shown on the table.

4.3.5.2 ICF Assessment of Sequestration Potential

ICF has also developed a sequestration potential assessment by reservoir type. The results of this assessment are summarized in Table 4-1. The Lower-48 assessed total is 3,375 Gt. The assessment includes estimates from DOE, and estimates for resources not convered by DOE. We have included a rough assessment of the Gulf of Mexico, as well as an estimate of shale gas sequestration potential. The ICF assessment can be broken out by state or region, and geologic category.

Table 4-2 presents the ICF Lower-48 assessment by region. Sequestration capacity associated with depleted oil and gas fields occurs where there has been significant production, including Appalachia, the Gulf Coast, Mid-Continent, and Rockies. Saline reservoir potential occurs in many areas of the country. Coalbed methane potential is concentrated in the large coalbed methane production areas such as New Mexico and Wyoming, while shale gas potential is associated with some of the new shale gas basins that have emerged over the past decade.

4-1. Comparison of ICF Assessment of U.S. Sequestration Potential with Published Estimates

Lower 48 Only Category	Aug 2007 ICF Gt CO2	ICF Lower-48 %	2008 NATCARB Low Gt CO2	2008 NATCARB High Gt CO2	2008 NATCARB Mid Gt CO2	2007 NATCARB Gt CO2	2006 NATCARB Gt CO2	2006 Batelle Gt CO2	2005 IEA Gt CO2
Depleted Oil and Gas Fields									
Depleted Oil Reservoirs with EOR Potential	**17**	**0.5%**					7	12	0 [1]
Depleted Conventional Oil Fields	**60**	**1.8%**					13	0 [1]	11
Depleted Gas Fields	**50**	**1.5%**					9	35	35
subtotal	**126**	**3.7%**	138	138	138	82	29	47	46
Coal and Coalbed Methane									
Enhanced CBM	**20**	**0.6%**					17	0 [1]	
Deep Unmineable Coal Seams	**32**	**0.9%**					11	30	60
subtotal	**52**	**1.5%**	73	94	84	86	28	30	60
Shale Formations	**107**	**3.2%**	0	0	0	0	45	0 [1]	0 [1]
Deep Saline Formations									
Onshore	**1,187**		2,130	7,950	5,040	1,907	6,595	2,730	2,730
Offshore	**1,803 [4]**		1,167	4,668	2,918 [4]	242 [3]	0 [1]	900	
subtotal	**2,990**	**88.6%**	3,297	12,618	7,958	2,149	6,595	3,630	2,730
Onshore Saline-Filled Basalt	**100**	**3.0%**				84	100	240	0
Lower-48 Total	**3,375**	**100.0%**	3,508	12,850	8,179	2,401	6,797	3,947	2,836
Alaska					84	84			
U.S.					8,263	2,485			

Notes:
1 No covereage in assessment.
2 Represents only a partial assessment of US.
3 Atlantic Offshore Only
4 GOM, Pacific and Atlantic Offshore

Table 4-2. Summary of ICF Sequestration Capacity Assessment

Gigatonnes of CO2 Storage

Region (Markal Region Name)	EOR	Depleted Oil Fields	Depleted Gas Fields	Coals	Shale	Saline	Basalt	Total
California (California)	1.2	8.0	1.8	0.0	0.0	161.1	0.0	172.2
Eastern Gulf Coast (East South Central)	0.2	1.1	1.3	1.9	28.0	103.2	0.0	135.6
Gulf of Mexico	1.5	5.5	8.4	0.0	0.0	800.0	0.0	815.3
Midwest (East North Central)	0.3	1.3	0.2	3.3	12.7	167.1	0.0	184.9
Northern Midcontinent (West North Central)	0.7	5.9	2.1	0.2	0.0	57.8	0.0	66.7
Northern Rockies (Mountain 1)	0.7	4.6	2.5	17.7	0.0	665.6	33.3	724.4
New England (New England)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Northeast (Middle Atlantic)	0.0	0.3	0.6	0.1	12.0	9.0	0.0	22.0
Pacific NW (Pacific; Lower 48 Onshore Part)	0.0	0.0	0.0	2.3	0.0	53.0	66.6	121.9
Pacific Offshore (Pacific; L48 Offshore)	0.0	1.2	0.0	0.0	0.0	100.0	0.0	101.3
Southern Rockies (Mountain 2)	1.4	3.3	6.0	19.6	0.0	36.5	0.0	66.8
Southeast (South Atlantic)	0.1	0.2	0.7	0.9	19.0	378.0	0.0	398.9
Texas and S. Midcontinent (West S. Central)	10.4	28.0	26.1	5.7	35.0	459.5	0.0	564.6
Total	16.5	59.5	49.7	51.6	106.7	2,990.6	99.9	3,374.6
Offshore (Gulf, Atlantic, Pacific)	1.5	6.7	8.4	0.0	0.0	1,186.6	0.0	1,203.3
Onshore	15.1	52.8	41.2	51.6	106.7	1,804.0	99.9	2,171.3

4.3.6 Geologic Sequestration Rule Activity Baseline

Based upon the above information on what is anticipated for R&D projects, FutureGen, and state programs, an activity baseline forecast of sequestration activity has been developed. Because of the uncertainty in which existing ER project might come under subpart RR, three scenarios have been created and are shown as Table 4-5 to 4-7. The first scenario assumes that no existing CO_2 ER projects choose to report as GS facilities. The second scenario assumes that all CO_2 ER projects from anthropogenic sources (7 million metric tons per year coming primarily from natural gas processing plants) choose to report as GS facilities. The third scenario assumes that all projects from anthropogenic CO_2 sources plus one-half of the remaining CO_2 flood projects choose to report as GS facilities. This third scenario adds up to 23.4 million metric tons per year injected of new (i.e., ignoring recycled volumes) CO_2.

The most comprehensive source of information on US ER projects is the annual survey conducted by the Oil and Gas Journal. The 105 projects listed in the Oil and Gas Journal 2007 ER survey were grouped by CO_2 source type – natural or anthropogenic. CO_2 use was allocated to the projects supplied by each source based on oil production. Anthropogenic sources were well defined for ER projects in Michigan (Antrim Gas Processing Plant), Wyoming/Colorado

(LaBarge/Shute Creek Gas Processing Plant), central Oklahoma (Enid Fertilizer Plant) and Kansas (US Energy Partners, Russell Kansas Ethanol Plant) from geographic proximity and information in published literature. Natural CO_2 production from the Jackson Dome in Mississippi was allocated to the 15 projects in Mississippi and Louisiana based on geographic proximity and information in published literature. Anthropogenic CO_2 from the Val Verde Gas Plant in Texas is mixed with CO_2 from natural sources and distributed to several fields in the Permian Basin so there was not a clear delineation of which projects were served by anthropogenic gas from the Val Verde plant. To estimate the number of facilities served by Val Verde, the total CO_2 use in the Permian Basin from natural sources and Val Verde production was summed and the percent of Val Verde production was prorated among the 66 projects in the Permian Basin. Val Verde CO_2 production represents 5.4 % of the total CO_2 used in the Permian Basin, therefore, the equivalent of approximately 4 projects in the Permian Basin are estimated to use anthropogenic CO_2 from Val Verde. For this analysis 2007 CO_2 production data for natural and anthropogenic sources was taken from the (1990-2007) Inventory of U.S. Greenhouse Gas Emissions and Sinks, and totaled 2.1 bcf/day which differs from the published DOE estimate of 2.6 bcf/day used in the threshold analysis.

Based on the number of projects active in 2007 (latest data available), anthropogenic sources provide approximately 18% of the mass of CO_2 used in ER projects in the US, and represent approximately 27 % of the CO_2 ER projects. These projects result in the additional production of more than 13 million barrels of oil annually. If only ER projects supplied by anthropogenic sources opted into the reporting program approximately 28 projects would be included. If all the ER projects supplied by anthropogenic sources, and half of the projects using natural sources opted into the reporting program approximately 67 projects would report, representing 1.2 bcf/day (23.4 million metric tons per year) or 59% of all CO_2 ER use.

Table 4-3. Pro-forma Project Characteristics (ER Scenario: No Additional ER Opt In)

	Baseline Forecast, # of Projects & Total Volumes		Per Project Averages for Economic Analysis (taken from ICF's UIC Class VI work)							
Type	Number of Projects Operating in 2012	Metric Tons CO_2 Injected per Year	Project Count	Monitoring Wells/ Project	Monitoring Well Depth Ft	Footage all monitoring wells	Square Miles/ Project	Producing Oil or Gas Wells/ Project	Project Life	Metric Tons CO_2 Injected per Year / Project
Known R&D ER	1	1,100,000	1	18	5,700	102,600	17.6	144	7	1,100,000
Known R&D Saline	6	2,720,000	1	3	8,000	24,000	1.7	0	7	750,557
Future R&D Saline	2	1,500,000	1	3	8,000	24,000	1.7	0	7	750,557
Known Commercial CO_2 Injection Facilities (No GS)	5	3,300,000	1	8	5,700	45,600	8.0	64	20	500,000
Known Commercial Saline	0	0	1	12	8,000	96,000	11.6	0	20	1,842,885
GS Facilities (ER opt in)	0	0	1	8	5,700	45,600	8.0	64	20	500,000

Table 4-4. Pro-forma Project Characteristics (ER Scenario: Anthropogenic ER Only Opt In)

	Baseline Forecast, # of Projects & Total Volumes		Per Project Averages for Economic Analysis (taken from ICF's UIC Class VI work)								
Type	Number of Projects Operating in 2012	Metric Tons CO_2 Injected per Year	Project Count	Monitoring Wells/ Project	Monitoring Well Depth Ft	Footage all monitoring wells	Square Miles/ Project	Producing Oil or Gas Wells/ Project	Project Life	Metric Tons CO_2 Injected per Year / Project
Known R&D ER	1	1,100,000	1	18	5,700	102,600	17.6	144	7	1,100,000
Known R&D Saline	6	2,720,000	1	3	8,000	24,000	1.7	0	7	750,557
Future R&D Saline	2	1,500,000	1	3	8,000	24,000	1.7	0	7	750,557
Known Commercial CO_2 Injection Facilities (No GS)	5	3,300,000	1	8	5,700	45,600	8.0	64	20	500,000
Known Commercial Saline	0	0	1	12	8,000	96,000	11.6	0	20	1,842,885
GS Facilities (ER opt in)	16	6,972,040	1	8	5,700	45,600	8.0	64	20	500,000

Table 4-5. Pro-forma Project Characteristics (ER Scenario: Anthropogenic plus One-half Other ER Opt In)

	Baseline Forecast, # of Projects & Total Volumes		Per Project Averages for Economic Analysis (taken from ICF's UIC Class VI work)							
Type	Number of Projects Operating in 2012	Metric Tons CO_2 Injected per Year	Project Count	Monitoring Wells/ Project	Monitoring Well Depth Ft	Footage all monitoring wells	Square Miles/ Project	Producing Oil or Gas Wells/ Project	Project Life	Metric Tons CO_2 Injected per Year / Project
Known R&D ER	1	1,100,000	1	18	5,700	102,600	17.6	144	7	1,100,000
Known R&D Saline	6	2,720,000	1	3	8,000	24,000	1.7	0	7	750,557
Future R&D Saline	2	1,500,000	1	3	8,000	24,000	1.7	0	7	750,557
Known Commercial CO_2 Injection Facilities (No GS)	5	3,300,000	1	8	5,700	45,600	8.0	64	20	500,000
Known Commercial Saline	0	0	1	12	8,000	96,000	11.6	0	20	1,842,885
GS Facilities (ER opt in)	48	23,543,741	1	8	5,700	45,600	8.0	64	20	500,000

4.3.6.1 Sources of Uncertainty

The activity baseline forecast of sequestration activity represents our best estimate of what will likely occur in the absence of national climate change legislation. As with any forecast, there are sources of uncertainty. Categories of uncertainty include:

- Number and timing of R&D projects and number of years of injection
- Number and timing of FutureGen projects and number of years of injection
- Number and timing of State Incentive projects and number of years of injection
- Average injection rates
- Number of ER projects that will be covered

Of the three categories of project, the least uncertainty is associated with the R&D projects. These projects have been funded and are expected to proceed at close to the announced schedule.

The DOE FutureGen project site has been chosen (Illinois) but there is still uncertainty about timing and injection volumes.

Given the number of state and regional initiatives underway it is very likely that projects related to state incentives will be initiated. As discussed previously, there are a number of projects for which either timing or injection volumes were not provided and were estimated by ICF.

The largest uncertainty over the timeframe of the activity baseline is what may occur at the national level in terms of climate change legislation. However, any costs associated with potential future national climate policy cannot be attributed to this subpart currently under consideration. The activity baseline presented in this document is expressly for the purpose of evaluating the costs of the subpart RR proposal under existing climate change policies.

4.4 Reporting Costs

4.4.1 Introduction

The purpose of this section is to present the unit cost estimates for the equipment and services that might be required to comply with the CO_2 Injection and GS Reporting rule and the total incremental annual cost of compliance. A base case is created assuming relevant monitoring costs are only that which is required under the UIC rules. Then three regulatory alternatives for reporting from geologic sequestration sites are evaluated in terms required technologies and practices and their costs.

4.4.2 Cost Assumptions and Methodology

The costs reported here include capital and operating and maintenance (O&M) including labor costs. They are based on hypothetical or pro-forma sites for various types of projects such as saline formation R&D GS projects, saline formation commercial GS projects, and ER GS projects. The geologic and engineering assumption for these pro-forma projects are the same as used by the EPA Office of Water in the proposed Federal Requirements under the Underground Injection Control Program for Carbon Dioxide Geologic Sequestration Wells, or the UIC Class VI proposal for CO_2 injection wells[37] for CO_2 injection wells. The Office of Water is currently updating the cost analysis used for the UIC Class VI proposal in preparation for the final rule. Once that data has been updated and made available, this cost analysis will be updated accordingly. The costs represent price levels in mid 2009, are presented in 2008 dollars. There were very steep increases in the costs of equipment, materials and labor used in the construction of all types of energy infrastructure including power plants, pipelines and oil and gas wells from 2004 through 2008. With the drop of oil and natural gas prices in the Fall of 2008 and the general economic decline around the world the costs of equipment, materials and labor have moderated somewhat.

4.4.2.1 Primary Data Sources for Costs

Table 4-8 summarizes the major data sources for costs used by EPA in the analysis geologic sequestration costs. A wide range of cost data is available from industry survey publications for costs typically incurred in oil and gas drilling and production operations. This includes drilling and completion costs by region and depth interval, equipment and operating

[37] The UIC rulemaking that would create a Class VI well class for injection of CO_2 for the purposes of GS was proposed July 25, 2008. (73 FR 43492)

costs, and pipeline costs. Data are available for both the U.S. and Canada. [38] [39] [40] [41]The cost of drilling and equipping wells represents a large component of sequestration costs. The costs of additional equipment or material specifications for CO_2 injection wells are based in part upon various sources for corrosion resistant materials and specific well components. Cost estimates for seismic data acquisition are also available from industry publications and presentations.

Labor rates are obtained from the U.S. Bureau of Labor Statistics and from surveys of oil and gas professional performed by the American Association of Petroleum Geologists (AAPG) and the Society of Petroleum Engineers (SPE). The number of hours required to carry out the various characterization or monitoring activities are ICF estimates that have been reviewed by the EPA workgroup.

No comprehensive source has been identified that provides detailed summaries of the full range of sequestration project cost components. Estimates of the costs of monitoring equipment, the number of stations required, and the cost of ongoing monitoring are based upon analysis of available literature and recent presentations by government and academic research groups and quotations from vendors. Some specific monitoring costs were obtained at a recent industry meeting sponsored by the Groundwater Protection Council.[42]

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[38] *Joint Association Survey of Drilling Costs*, American Petroleum Institute, Washington, DC. http://www.api.org/statistics/accessapi/api-reports.cfm

[39] *PSAC Well Cost Study – 2008,* Petroleum Services Association of Canada, October 30, 2007.

[40] *Oil and Gas Lease Equipment and Operating Costs*, U.S. Energy Information Administration, 2006, http://www.eia.doe.gov/pub/oil_gas/natural_gas/data_publications/cost_indices_equipment_production/current/coststudy.html

[41] *Oil and Gas Journal Pipeline Cost Survey*, Oil and Gas Journal Magazine, September 3, 2007.

[42] Ground Water Protection Council Meeting, New Orleans, LA, January, 16, 2008.

Table 4-6. Major Sources of Geologic Sequestration Cost Information

Source	Cost Categories
API Joint Association Survey of Drilling Costs	Drilling costs in the U.S. for oil, gas, and dry holes by depth interval
EIA Oil and Gas Lease Equipment and Operating Cost Survey	Surface equipment costs, annual operating costs, pump costs
Pipeline Prime Mover and Compressor Costs (FERC)	Pumps
2008 Petroleum Services of Canada Well Cost Study (PSAC)	Drilling costs, plugging costs, logging costs
Oil and Gas Journal Report on Pipeline and Cost Data Reported to FERC	Pipeline costs per inch-mile
Land Rig Newsletter	Onshore rig day rates/ well cost algorithms
New Orleans Sequestration Technology Meeting, January, 2008	Monitor station costs in several categories; seismic costs
FutureGen Sequestration Site Submittals	Monitoring station layout/number of stations
Preston Pipe Report	Casing and tubing costs
Hourly Labor Rates	U.S. Bureau of Labor Statistics
Selected Presentations and Papers (see below)	Sensor costs, monitoring costs, number of stations, seismic costs

Significant Papers and Presentations With Cost Data

Benson, "Monitoring Protocols and Life Cycle Costs for Geologic Storage of Carbon Dioxide", Sept., 2004
IEA Greenhouse Gas Programme Report PH4/29, "Overview of Monitoring Requirements for Geologic Storage Projects, Nov., 2004.
Hoversten, "Investigation of Novel Geophysical Techniques for Monitoring CO2 Movement During Sequestration," Oct., 2003.
Dahowski, et al, " The Costs of Applying Carbon Dioxide Capture and Geologic Storage Technologies to Two Hypothetical Coal to Liquids Production Configurations: A Preliminary Estimation," Pacific NW National Laboratory, September, 2007.

The assumed capital costs and the annual operating cost of the various monitoring technologies whose application might be affected by the GS Reporting rule are shown in Table 4-9 and 4-10. The capital costs are annualized using a capital recovery factor of 0.186 for projects lasting 7 years and 0.094 for projects lasting 20 years. The annual O&M costs are added to the annualized capital costs to determine total annual direct costs. To this is added a 20 percent overhead and general and administrative cost factor to obtain total annual costs. These are then divided by the amount assumed to be injected each year in the pro-forma project to arrive at total costs per metric ton of CO_2 injected. These per-ton costs are then used to estimate total annual costs for the level of injection expected in the activity baseline.

4.4.3 Monitoring, Reporting, and Verification (MRV) Plan Requirements and Approval Process

There are two types of sites that will report under Subpart RR, injection facilities and a subset of injection facilities conducting GS (i.e. GS facilities). All sites will incur the periodic sampling and testing costs, however only GS facilities will incur the monitoring plan related costs. EPA proposes that GS facilities must develop an MRV plan, submit it to EPA for approval, and implement it once approved by EPA to report the amount of CO_2 that has been sequestered. EPA is proposing that each submitted MRV plan must include at a minimum the four requirements described below.

Step 1 – Assessment of Risk of Leakage: All potential pathways that may result in CO_2 leakage have been identified and characterized and the risk of CO_2 leakage at each pathway has been evaluated;

Step 2 – Strategy for Detecting and Quantifying CO_2 Leakage to Surface: Potential pathways will be monitored according to the risk of CO_2 leakage to ensure that any leakage to the surface will be detected and that leakage to the surface, should it occur, will be quantified according to a specified methodology;

Step 3 - Strategy for Establishing Pre-Injection Environmental Baselines: Environmental baselines against which the monitoring results will be evaluated have been established at potential leakage pathways; and

Step 4 - Tailor Mass Balance Equation: Site-specific variables have been considered and developed for the mass balance equation provided in the regulatory text to calculate the amount of CO_2 sequestered.

Table 4-7. Unit Cost of Relevant Continuous and Periodic Monitoring Technologies

Item	Capital Cost to Establish Environmental Baseline	Capital Cost for Construction and Equipment	Operating Cost
Deep Monitoring Wells (into or right above injection zone)	$200 lab fee per sample plus $1,000 to collect. 4 samples per well is $4,800 per well.	$20,000 + $5,000/well for design, $10,000 per well for surface disturbance, $165-$200 per foot to build, $20,000 for equipment	Annual O&M costs are $25,000 + $3/ft per well per year
CO_2 Flow Meters on Producing Oil and Gas Wells	NA	$10,000/ oil well	Annual O&M costs are $500 per well per year
CO_2 Flow & Gas Composition Meters on Producing Oil and Gas Wells	NA	$50,000/ oil well	Annual O&M costs are $2,500 per well per year
Periodic Sampling and Testing of Injected Fluid	NA	12 hours @$107.23/hr = $1,286 for plan	$200 lab fee per sample plus $270 to collect.
Estimation of Fugitive Emission from Surface Facilities	NA	40 hours @$107.23/hr = $4,289 for planning and initial inventory of facilities	24 hours @$107.23/hr = $2,574 for annual calculations

Item	Capital Cost to Establish Environmental Baseline	Capital Cost for Construction and Equipment	Operating Cost
Periodic Seismic Surveys	Seismic survey baseline established as part of site characterization. No extra cost for monitoring.	No construction costs, but planning and quality assurance costs would add $25,000 per project.	$100,000 per square mile
Periodic Digital Color Infrared Orthoimagery (CIR) or Hyperspectral Imaging to detect changes to vegetation.	Initial survey before injection commences would establish baseline.	No construction costs, but planning and quality assurance costs would add $10,000 per square mile.	Airborne survey costs $250 per linear mile. Assuming interline spacing of 200-250 feet, a square mile would take about 25 passes and cost $6,250. Plus mobilization costs of $5,000 per site.
Periodic airborne survey to detect surface leaks. Works best where vegetation is sparse.	NA	No construction costs, but planning and quality assurance costs would add $10,000 per square mile.	Airborne survey costs $250 per linear mile. Assuming interline spacing of 200-250 feet, a square mile would take about 25 passes and cost $6,250. Plus mobilization costs of $5,000 per site.
Eddy covariance measurement from permanent towers to detect surface leaks.	Establishing baseline is $35,000 per station.	40 hours @$107.23/hr = $4,289 for plan plus $70,000/monitoring site.	$10,000 per station per year
Soil zone monitoring (sampling gas from accumulation chambers)	Initial survey before injection commences would establish baseline.	40 hours @$107.23/hr = $4,289 for plan plus $6,000/monitoring site	$200 lab fee per sample plus $100 to collect.
Vadose zone monitoring wells to sample gas above water table.	Initial survey before injection commences would establish baseline.	40 hours @$107.23/hr = $4,289 for plan plus $8,000/monitoring site	$200 lab fee per sample plus $100 to collect.
Monitoring wells for samples from water table.	Initial survey before injection commences would establish baseline.	40 hours @$107.23/hr = $4,289 for plan plus $80,000/monitoring site	$200 lab fee per sample plus $1,000 to collect.

Table 4-8. Unit Cost of Relevant Episodic Monitoring Technologies (That may be employed after a subsurface leak is detected)

Detection Method	Method of Quantification	Estimate of Unit Cost for Leak Quantification	Cost per Episode	Probability of Detection Method Deployment	Additional Annual Cost per Project for Leak Quantification
Surface leak detected by air, soil or water table monitoring.	Detailed seismic survey plus reservoir simulation to estimate leak volume at subsurface to help calibrate leak volume into atmosphere	$100,00 per square mile per survey. Leak volume estimation process 160 hours @$110.62/hr.	$117,698	1.0%	$1,177
Surface leak detected by air, soil or water table monitoring	Tenting of area to estimate leak volume	Assume 30 minutes per tent survey location by two technicians @$100/hr each plus mobilization costs of $5,000. If 640 locations are surveyed (one per acre), cost is $69,000 per square mile. Leak volume estimation process 80 hours @$110.62/hr.	$77,849	1.0%	$778
			Total per Year	**2.0%**	**$1,955**
Note: Assumes survey for leak occurs over one square mile area in each episode. Project's area is 10 square miles.					

4.5 Monitoring Technologies

Deep Monitoring Wells

Deep monitoring wells are typically drilled to monitor the deepest permeable zone above the caprock. Downhole instrumentation can be used to monitor pressure, temperature, and conductivity/salinity. Alternatively, U-tube devices can be used to retrieve pressurized samples for laboratory testing. Other types of monitoring from wells include micro-seismic, cross-well resistivity, and vertical seismic profiling.

CO_2 Flow Meters on Producing Oil and Gas Wells

Meters, probably located after the wellhead separator, that continuously measure the pressure, temperature and flow rate of the gas from a well. The composition of the gas is analyzed periodically using a gas chromatograph to determine percent CO_2 concentration. The mass of CO_2 passing through the wellhead can then be calculated from the measured quantities.

CO_2 Flow and Gas Composition Meters on Producing Oil and Gas Wells

Meters, probably located after the wellhead separator, that continuously measure the pressure, temperature, flow rate and chemical composition of the gas from a well. The mass of CO_2 passing through the wellhead can then be calculated from the measured quantities. This differs from the item directly above in that the chemical composition of the gas is being measured automatically by the meter itself rather through periodically obtaining a sample and sending it to lab for analysis.

Periodic Sampling and Testing of Injected Fluid

All injection and GS facilities will incur periodic sampling and testing costs. To estimate the costs, we have applied similar assumptions that were used in Subpart OO for sampling and testing of industrial gases. For example, we have assumed that it takes 12 labor hours to contact an onsite laboratory or offsite vendor and develop a plan; to collect and send the sample to an onsite or offsite laboratory; and to provide data invoice if sent offsite. Furthermore, we have assumed that it costs approximately $500 per sample to collect and conduct the test of chemical composition. In addition to these costs, GS facilities will additionally incur the costs described in this rule.

Seismic Surveys

Seismic data acquisition involves the generation and detection of sound waves to evaluation conditions in the subsurface. Periodic acquisition of seismic data can be used to detect subsurface CO_2 movement within and outside of the reservoir.

Digital Color Infrared Ortho-imagery and Hyper-spectral Imaging

Digital color ortho-imagery and hyper-spectral imaging are airborne remote sensing technologies that are used to detect changes in vegetation resulting from CO_2 leaks. Hyperspectral sensors look at objects using electromagnetic spectrum. The object is to detect a specific spectral signature that is known to result from CO_2 uptake. The advantage of these methods is that they can efficiently cover a large surface area.

Airborne Survey (LIDAR)

LIDAR (Light Detection and Ranging) involves the transmission of light from an instrument to a target and the recording of the reflected light to determine some property of the target. Differential Absorption LIDAR (DIAL) uses two wavelengths of laser to measure CO_2. The wavelengths used are specific to CO_2. One wavelength is selected to correspond to a CO_2 spectral absorption line, while the other is a non-absorbing wavelength. The difference in intensity of the two return signals is a measure of concentration.

Airborne Survey (CO_2 Detectors)

CO_2 detectors are commercially available for short closed-path and short open-path (point) measurements and long open-path (radial line) measurements. Similar detectors have been integrated into stationary, mobile, and airborne monitoring packages that are commonly used in combination with high-resolution global positioning system (GPS) to detect and quantify methane leaks in areas with road access. While these packages have not been widely tested for CO_2, various types of CO_2 monitors are commercially available and could be used in these applications. Such monitoring techniques are likely the leading candidates for monitoring plan applications because of their low cost and high reliability. The technologies include *infrared gas analyzers* (IRGAs, including Fourier transform infrared (FTIR) and non-dispersive infrared (NDIR) analyzers), tunable diode lasers (TDLs), cavity ring down techniques, and others. The sample path can range from 10 cm to 1 km, by reflecting a laser beam off retro-reflecting mirrors. These devices measure the gas concentration, and, when packaged with measurements of wind speed and wind direction, they measure the total gas flow.

Eddy Covariance

Eddy Covariance is a technique whereby high frequency measurements of atmospheric CO_2 concentration at a height above the ground are made by an infra-red gas analyzer along with measurements of micro-meteorological variables such as wind velocity, direction, humidity, and temperature. Integration of these data allows derivation of the net CO_2 flux over the upwind footprint, typically square meters to square kilometers in area.

Soil Zone Monitoring with Accumulation Chamber (AC)

Surface CO_2 flux is measured using an accumulation chamber. The chamber is made of stainless steel with an open bottom and is placed at the sampling location. It may be placed either directly on the ground or on a collar installed in the ground surface. The air is circulated through the AC and measured with and infra-red gas analyzer.

Vadose Zone Monitoring

The vadose zone is the relatively shallow zone beneath the soil zone that is not saturated with groundwater. Small diameter probes are installed in the zone and samples are taken. The CO_2 concentration of air samples taken in this zone can be measured by and infrared gas analyzer.

Monitoring Wells for Water Table Sampling

Shallow monitoring wells may be used to measure the properties of ground water. Such wells are typically no deeper than several hundred feet.

Estimating Leak Volumes after a Leak is Detected

The monitoring program for GS facilities may detect subsurface leaks and it will be necessary to estimate the volume of leaks to the surface to comply with the reporting requirements of this rule. Each site operator will have to devise suitable techniques taking into account the geology of the sites, the location and nature of the potential leaks and the performance characteristics of available monitoring and measurement technologies.

It is expected that these estimates may include engineering estimates as well as some direct measurement and may have a wide margin of uncertainty. It is expected that site characterization and screening will lead to selection of sites that are suitable for long-term sequestration and that incidences of leaks to the surface may be infrequent at well-selected and well-managed sites. The cost estimates presented here for subsurface leak quantification assume a two percent chance in one year that any given site will have to implement the leak quantification strategy described in the site's MRV plan. There are no operating statistics for CO_2 GS from which to draw any citable conclusions on how often leaks to the surface may be detected, therefore a very conservative estimate was used in order to estimate the potential cost.

If the leak is detected in the subsurface (possibly by anomalous pressure readings in a monitoring well) the leak volume may be estimated to help calibrate a leak volume to the surface. Quantification is presumed to be done using engineering calculations supplemented, when technically feasible, by direct observation/measurement using, for example, a 3-D seismic survey over the area of the suspected leak. The seismic survey might be able to detect the location, size and density of the CO_2 plume formed by the leak in one or more containment zones located above the injection zone. The volume of the leak also might be estimated using a reservoir simulation model of the containment zone calibrated to the pressure readings of the monitoring wells surrounding the location of the leak. In other words, different volumes of leaks would be tested in the reservoir simulator to find which leak volume most closely matches the pressure history observed in the surrounding monitoring wells.

Leaks may also be detected at or near the surface by air, soil gas and water table monitoring devices. It is possible that some of the monitoring devices, such as eddy covariance, could themselves be used to estimate leak volumes. Another possible way of estimating the volume of a leak at the surface is to place a tent over the area of the leak. The tent would be sealed at the ground by weights or spikes and a calibrated volume of gas such as nitrogen would be introduced into the tent and allowed to escape through a chimney at the top of the tent. By measuring the concentration of CO_2 in the gases leaving the chimney it is possible to measure the amount of CO_2 leaving the ground in the area of the tent. The tent would have to be moved to many locations and the process repeated to get a representative sample over the entire area of the leak. It also would be necessary to correct the readings for natural CO_2 fluxes into and out of the soil.

Many of the leak detection methods for onshore GS sites can be applied to sub-seabed sites. These include monitoring of the injection well and monitoring of the subsurface CO_2 plume: active seismic, passive seismic, sensors in deep monitoring wells, and reservoir modeling. Though there will be differences in monitoring approaches at sub-seabed GS sites for leak detection and quantification, the cost estimates are assumed to be comparable.

Labor Rates

The cost of labor for many of the cost items in Table 4-9 and 4-10 and for General and Administrative Costs are based on Society of Petroleum Engineers (SPE) 2008 annual salary survey.[43] The average salary for a petroleum reservoir engineer with 15 years of experience is

[43] For SPE survey of petroleum engineers see http://www.spe.org/spe-site/spe/spe/career/salary_survey/08SalarySurveyHighlights.pdf

$143,800. Applying a 1.6 fringe and overhead factor yields an hourly burdened labor cost of $110.62 per hour.

The unit costs values shown in Table 4-9 and 4-10 reflect the cost of goods and services that would be purchased by the entity which owns the GS facility. That entity would have additional General and Administrative Costs (G&A) on top of those direct costs for goods and services. These G&A cost are assumed to 20 percent of the direct costs.

4.5.1 Cost Scenarios

There are three regulatory alternatives (low, medium [or reference], and high) presented in Table 4-11 in terms of which monitoring devices would be used at a GS facility and how often sampling and measurement would take place. Because each GS facility will have unique characteristics that may result in the selection of different monitoring techniques, the application of the monitoring devices are indicated as percents of sites that would be expected to use each device or technique. Also shown in Table 5-4 are the portions of facilities that expected to be required to use the device or technique under the UIC Class VI permits and under UIC Class II permits. The cost impacts of the Rule RR are estimated as the monitoring and measurement requirements above and beyond the UIC Class II requirements. [44]

[44] For the purposes of this proposed rule, costs incremental to Class II requirements were estimated for ER projects conducting GS and costs incremental to the proposed Class VI requirements were estimated for all other GS projects.

Table 4-9. Assumptions for Application of Technologies by Regulatory Alternative

		Saline, Abandoned Oil & Gas Fields: Starting Point is UIC Class VI Requirements				ER plus GS: Starting Point is UIC Class II Requirements			
		Under UIC Class VI	Lowest Level RR Alternative	Middle Level RR Alternative	Highest Level RR Alternative	Under UIC Class II	Lowest Level RR Alternative	Middle Level RR Alternative	Highest Level RR Alternative
Deep Monitoring Wells (into or right above injection zone)	Fraction Projects	100%	100%	100%	100%	0%	100%	100%	100%
	Frequency (months)	Continuous	Continuous	Continuous	Continuous		Continuous	Continuous	Continuous
CO_2 Flow Meters on Producing Oil and Gas Wells	Fraction Projects	0%	0%	0%	0%	0%	100%	100%	100%
	Frequency (months)						Continuous	Continuous	Continuous
CO_2 Flow & Gas Composition Meters on Producing Oil and Gas Wells	Fraction Projects	0%	0%	0%	0%	0%	0%	0%	0%
	Frequency (months)						Continuous	Continuous	Continuous
Periodic Sampling and Testing of Injected Fluid	Fraction Projects	100%	100%	100%	100%	100%	100%	100%	100%
	Frequency (months)	3	3	3	3	3	3	3	3
Estimation of Fugitive Emission from Surface Facilities	Fraction Projects	0%	0%	100%	100%	0%	0%	0%	0%
	Frequency (months)	12	12	12	12	12	12	12	12
Periodic Seismic Surveys	Fraction Projects	25%	25%	25%	25%	0%	25%	25%	25%
	Frequency (months)	60	60	60	60	60	60	60	60
Periodic Digital Color Infrared Orthoimagery (CIR) or Hyperspectral Imaging to detect changes to vegetation.	Fraction Projects	0%	0%	50%	50%	0%	0%	50%	50%
	Frequency (months)	12	12	12	12	12	12	12	12

Table 4-9. Assumptions for Application of Technologies by Regulatory Alternative (continued)

		Saline, Abandoned Oil & Gas Fields: Starting Point is UIC Class VI Requirements				ER plus GS: Starting Point is UIC Class II Requirements			
		Under UIC Class VI	Lowest Level RR Alternative	Middle Level RR Alternative	Highest Level RR Alternative	Under UIC Class II	Lowest Level RR Alternative	Middle Level RR Alternative	Highest Level RR Alternative
Periodic LIDAR airborne survey to detect surface leaks. Works best where vegetation is sparse.	Fraction Projects	0%	0%	50%	50%	0%	0%	50%	50%
	Frequency (months)	12	12	12	12	12	12	12	12
Eddy covariance measurement from permanent towers to detect surface leaks.	Fraction Projects	25%	25%	25%	100%	0%	25%	25%	100%
	Frequency (months)	Continuous	Continuous	Continuous	Continuous	Continuous	Continuous	Continuous	Continuous
Soil zone monitoring (sampling gas from accumulation chambers)	Fraction Projects	0%	0%	100%	100%	0%	0%	100%	100%
	Frequency (months)	12	12	12	3	12	12	12	3
Vadose zone monitoring wells to sample gas above water table.	Fraction Projects	0%	0%	100%	100%	0%	0%	100%	100%
	Frequency (months)	12	12	12	3	12	12	12	3
Monitoring wells for samples from water table.	Fraction Projects	0%	0%	100%	100%	0%	0%	100%	100%
	Frequency (months)	12	12	12	3	12	12	12	3

4.6 Projecting and Discounting National Costs

The cost per project is computed by applying the cost algorithms (Table 4-5 and 4-8) to the "pro-forma" characteristics assume for each type of project (Tables 4-3 to 4-5), "Pro-form Project Characteristics." The results for cost per project appear in the left-hand side of Table 4-10 for the no additional ER opt in activity baseline scenario. Table 4-11 shows the results for the anthropogenic ER opt in only activity scenario. Table 4-12 shows the results for the anthropogenic plus one half of other ER opt in activity scenario.

Table 4-10. Summary of Cost Impacts: Activity Baseline with No Additional ER Opt In

		Environmental Baseline		Periodic Monitoring			Annual		
	Type	Capital Costs	Annualized Capital Costs	Capital Cost	Annual Operating Cost	Annualized Capital and Contractor Costs	Episodic Monitoring Costs	Overhead and G&A	Total Annual Costs Per Project
Under UIC Class VI or II	Known R&D ER	$0	$0	$1,286	$1,880	$2,119	$0	$424	$2,542
	Known R&D Saline	$7,438	$1,380	$4,122,722	$159,505	$924,489	$0	$185,174	$1,111,043
	Future R&D Saline	$7,438	$1,380	$4,122,722	$159,505	$924,489	$0	$185,174	$1,111,043
	Known Commercial CO2 Injection Facilities (No GS)	$0	$0	$1,286	$1,880	$2,001	$0	$400	$2,402
	Known Commercial Saline	$50,750	$4,790	$16,452,855	$662,380	$2,215,413	$0	$444,041	$2,664,244
	GS Facilities (ER opt in)	$0	$0	$1,286	$1,880	$2,001	$0	$400	$2,402
Low	Known R&D ER	$77,000	$14,288	$19,276,372	$941,680	$4,518,473	$3,442	$907,240	$5,443,443
	Known R&D Saline	$7,438	$1,380	$4,122,722	$159,505	$924,489	$1,955	$185,565	$1,113,390
	Future R&D Saline	$7,438	$1,380	$4,122,722	$159,505	$924,489	$1,955	$185,565	$1,113,390
	Known Commercial CO2 Injection Facilities (No GS)	$35,000	$3,304	$8,584,225	$420,680	$1,230,970	$1,955	$247,246	$1,483,475
	Known Commercial Saline	$50,750	$4,790	$16,452,855	$662,380	$2,215,413	$2,268	$444,494	$2,666,966
	GS Facilities (ER opt in)	$35,000	$3,304	$8,584,225	$420,680	$1,230,970	$1,955	$247,246	$1,483,475
Reference	Known R&D ER	$166,180	$30,835	$21,333,231	$1,088,360	$5,046,810	$3,442	$1,016,217	$6,097,304
	Known R&D Saline	$18,310	$3,397	$4,325,685	$180,764	$983,409	$1,955	$197,752	$1,186,514
	Future R&D Saline	$18,310	$3,397	$4,325,685	$180,764	$983,409	$1,955	$197,752	$1,186,514
	Known Commercial CO2 Injection Facilities (No GS)	$76,900	$7,259	$9,519,161	$490,080	$1,388,621	$1,955	$279,567	$1,677,403
	Known Commercial Saline	$110,380	$10,419	$17,812,801	$763,334	$2,444,736	$2,268	$491,485	$2,948,909
	GS Facilities (ER opt in)	$76,900	$7,259	$9,519,161	$490,080	$1,388,621	$1,955	$279,567	$1,677,403
High	Known R&D ER	$397,180	$73,698	$21,823,538	$1,249,400	$5,298,828	$3,442	$1,075,193	$6,451,161
	Known R&D Saline	$40,623	$7,538	$4,373,045	$196,319	$1,007,751	$1,955	$203,449	$1,220,694
	Future R&D Saline	$40,623	$7,538	$4,373,045	$196,319	$1,007,751	$1,955	$203,449	$1,220,694
	Known Commercial CO2 Injection Facilities (No GS)	$181,900	$17,170	$9,742,028	$563,280	$1,482,859	$1,955	$300,397	$1,802,381
	Known Commercial Saline	$262,630	$24,790	$18,135,958	$869,474	$2,581,380	$2,268	$521,688	$3,130,127
	GS Facilities (ER opt in)	$181,900	$17,170	$9,742,028	$563,280	$1,482,859	$1,955	$300,397	$1,802,381

Table 4-11. Summary of Cost Impacts: Activity Baseline from only Anthropogenic ER Opt In

		Environmental Baseline		Periodic Monitoring			Annual		
	Type	Capital Costs	Annualized Capital Costs	Capital Cost	Annual Operating Cost	Annualized Capital and Contractor Costs	Episodic Monitoring Costs	Overhead and G&A	Total Annual Costs Per Project
Under UIC Class VI or II	Known R&D ER	$0	$0	$1,286	$1,880	$2,119	$0	$424	$2,542
	Known R&D Saline	$7,438	$1,380	$4,122,722	$159,505	$924,489	$0	$185,174	$1,111,043
	Future R&D Saline	$7,438	$1,380	$4,122,722	$159,505	$924,489	$0	$185,174	$1,111,043
	Known Commercial CO2 Injection Facilities (No GS)	$0	$0	$1,286	$1,880	$2,001	$0	$400	$2,402
	Known Commercial Saline	$50,750	$4,790	$16,452,855	$662,380	$2,215,413	$0	$444,041	$2,664,244
	GS Facilities (ER opt in)	$0	$0	$1,286	$1,880	$2,001	$0	$400	$2,402
Low	Known R&D ER	$77,000	$14,288	$19,276,372	$941,680	$4,518,473	$3,442	$907,240	$5,443,443
	Known R&D Saline	$7,438	$1,380	$4,122,722	$159,505	$924,489	$1,955	$185,565	$1,113,390
	Future R&D Saline	$7,438	$1,380	$4,122,722	$159,505	$924,489	$1,955	$185,565	$1,113,390
	Known Commercial CO2 Injection Facilities (No GS)	$35,000	$3,304	$8,584,225	$420,680	$1,230,970	$1,955	$247,246	$1,483,475
	Known Commercial Saline	$50,750	$4,790	$16,452,855	$662,380	$2,215,413	$2,268	$444,494	$2,666,966
	GS Facilities (ER opt in)	$35,000	$3,304	$8,584,225	$420,680	$1,230,970	$1,955	$247,246	$1,483,475
Reference	Known R&D ER	$166,180	$30,835	$21,333,231	$1,088,360	$5,046,810	$3,442	$1,016,217	$6,097,304
	Known R&D Saline	$18,310	$3,397	$4,325,685	$180,764	$983,409	$1,955	$197,752	$1,186,514
	Future R&D Saline	$18,310	$3,397	$4,325,685	$180,764	$983,409	$1,955	$197,752	$1,186,514
	Known Commercial CO2 Injection Facilities (No GS)	$76,900	$7,259	$9,519,161	$490,080	$1,388,621	$1,955	$279,567	$1,677,403
	Known Commercial Saline	$110,380	$10,419	$17,812,801	$763,334	$2,444,736	$2,268	$491,485	$2,948,909
	GS Facilities (ER opt in)	$76,900	$7,259	$9,519,161	$490,080	$1,388,621	$1,955	$279,567	$1,677,403
High	Known R&D ER	$397,180	$73,698	$21,823,538	$1,249,400	$5,298,828	$3,442	$1,075,193	$6,451,161
	Known R&D Saline	$40,623	$7,538	$4,373,045	$196,319	$1,007,751	$1,955	$203,449	$1,220,694
	Future R&D Saline	$40,623	$7,538	$4,373,045	$196,319	$1,007,751	$1,955	$203,449	$1,220,694
	Known Commercial CO2 Injection Facilities (No GS)	$181,900	$17,170	$9,742,028	$563,280	$1,482,859	$1,955	$300,397	$1,802,381
	Known Commercial Saline	$262,630	$24,790	$18,135,958	$869,474	$2,581,380	$2,268	$521,688	$3,130,127
	GS Facilities (ER opt in)	$181,900	$17,170	$9,742,028	$563,280	$1,482,859	$1,955	$300,397	$1,802,381

Table 4-12. Summary of Cost Impacts: Activity Baseline from Anthropogenic CO_2 plus One-half of Other ER Opt In

		Environmental Baseline		Periodic Monitoring			Annual		
	Type	Capital Costs	Annualized Capital Costs	Capital Cost	Annual Operating Cost	Annualized Capital and Contractor Costs	Episodic Monitoring Costs	Overhead and G&A	Total Annual Costs Per Project
Under UIC Class VI or II	Known R&D ER	$0	$0	$1,286	$1,880	$2,119	$0	$424	$2,542
	Known R&D Saline	$7,438	$1,380	$4,122,722	$159,505	$924,489	$0	$185,174	$1,111,043
	Future R&D Saline	$7,438	$1,380	$4,122,722	$159,505	$924,489	$0	$185,174	$1,111,043
	Known Commercial CO2 Injection Facilities (No GS)	$0	$0	$1,286	$1,880	$2,001	$0	$400	$2,402
	Known Commercial Saline	$50,750	$4,790	$16,452,855	$662,380	$2,215,413	$0	$444,041	$2,664,244
	GS Facilities (ER opt in)	$0	$0	$1,286	$1,880	$2,001	$0	$400	$2,402
Low	Known R&D ER	$77,000	$14,288	$19,276,372	$941,680	$4,518,473	$3,442	$907,240	$5,443,443
	Known R&D Saline	$7,438	$1,380	$4,122,722	$159,505	$924,489	$1,955	$185,565	$1,113,390
	Future R&D Saline	$7,438	$1,380	$4,122,722	$159,505	$924,489	$1,955	$185,565	$1,113,390
	Known Commercial CO2 Injection Facilities (No GS)	$35,000	$3,304	$8,584,225	$420,680	$1,230,970	$1,955	$247,246	$1,483,475
	Known Commercial Saline	$50,750	$4,790	$16,452,855	$662,380	$2,215,413	$2,268	$444,494	$2,666,966
	GS Facilities (ER opt in)	$35,000	$3,304	$8,584,225	$420,680	$1,230,970	$1,955	$247,246	$1,483,475
Reference	Known R&D ER	$166,180	$30,835	$21,333,231	$1,088,360	$5,046,810	$3,442	$1,016,217	$6,097,304
	Known R&D Saline	$18,310	$3,397	$4,325,685	$180,764	$983,409	$1,955	$197,752	$1,186,514
	Future R&D Saline	$18,310	$3,397	$4,325,685	$180,764	$983,409	$1,955	$197,752	$1,186,514
	Known Commercial CO2 Injection Facilities (No GS)	$76,900	$7,259	$9,519,161	$490,080	$1,388,621	$1,955	$279,567	$1,677,403
	Known Commercial Saline	$110,380	$10,419	$17,812,801	$763,334	$2,444,736	$2,268	$491,485	$2,948,909
	GS Facilities (ER opt in)	$76,900	$7,259	$9,519,161	$490,080	$1,388,621	$1,955	$279,567	$1,677,403
High	Known R&D ER	$397,180	$73,698	$21,823,538	$1,249,400	$5,298,828	$3,442	$1,075,193	$6,451,161
	Known R&D Saline	$40,623	$7,538	$4,373,045	$196,319	$1,007,751	$1,955	$203,449	$1,220,694
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	Known Commercial CO2 Injection Facilities (No GS)	$181,900	$17,170	$9,742,028	$563,280	$1,482,859	$1,955	$300,397	$1,802,381
	Known Commercial Saline	$262,630	$24,790	$18,135,958	$869,474	$2,581,380	$2,268	$521,688	$3,130,127
	GS Facilities (ER opt in)	$181,900	$17,170	$9,742,028	$563,280	$1,482,859	$1,955	$300,397	$1,802,381

4.7 Other Recordkeeping and Reporting Costs

Additional recordkeeping ($1,700 per entity) and reporting ($500) costs per field were also added to each project type.

4.8 Public Sector Burden

EPA estimates the public sector burden to be $344,000 per year; $55,000 per year is for verification activities, and remaining costs are for program implementation and developing and maintaining the data collection system. Program implementation activities include, but are not limited to, evaluating monitoring plans, developing guidance and training materials to assist the regulated community, responding to inquires from affected facilities on monitoring and applicability requirements, and developing tools to assist in determining applicability.

SECTION 5
ECONOMIC IMPACT ANALYSIS

EPA prepares an EIA to provide decision makers with a measure of the social costs of using resources to comply with a program (EPA, 2000). As noted in EPA's (2000) *Guidelines for Preparing Economic Analyses*, several tools are available to estimate social costs and range from simple direct compliance cost methods to the development of a more complex market analysis that estimates market changes (e.g., price and consumption) and economic welfare changes (e.g., changes in consumer and producer surplus). Given data limitations and the size scope of the proposed rule, EPA has used the direct compliance cost method as a measure of social costs[45].

5.1 Threshold Analysis

EPA considered both a threshold based on the amount of CO_2 emitted and a threshold based on the amount of CO_2 injected underground. EPA concluded that an emissions-based threshold would be problematic because of the lack of data on the incidence and scale of surface emissions and leakage from injection and GS of facilities. EPA accordingly analyzed injection facilities based on the quantity of CO_2 injected underground and considered whether an injection threshold should apply. EPA evaluated a no threshold option (i.e., all facilities that inject CO_2 would be required to report), 1,000 metric tons per year, 10,000 metric tons per year, 25,000 metric tons per year, and 100,000 metric tons per year per facility of CO_2 injected. The results of the threshold analysis are presented below in Table 5-1. For further information on the assumptions underlying the threshold analysis, please refer to the general technical support document (TSD) for this proposal.[46]

[45] See pages 124 and 125 (EPA, 2000).
[46] Subpart RR General TSD (see docket ID No. EPA-HQ-OAR-2009-0926)

Table 5-1 CO_2 Injection Facilities: Effect of Injection Threshold on Reported Amount of CO_2 Injected and Number of Facilities Required to Report

Threshold Level (metric tons/yr of CO_2 injected)	Total National (metric tons/yr of CO_2 injected)	Total Number of U.S. Facilities	Amount of CO_2 Injected		Number of Facilities	
			Metric tons/yr of CO_2 Injected	Percent Covered	Number	Percent Covered
All In	40,111,639	80	40,111,639	100.0%	80	100.0%
1,000	40,111,639	80	40,111,115	100.0%	74	92.5%
10,000	40,111,639	80	40,099,065	100.0%	71	88.8%
25,000	40,111,639	80	40,005,238	100.0%	65	81.3%
100,000	40,111,639	80	39,065,039	97.4%	48	60.0%

EPA is proposing that all CO_2 injection facilities would be required to report the minimum information in subpart RR (quantity of CO_2 injected, quantity of CO_2 transferred onsite from offsite, and source of the CO_2 if known) at no threshold. An all-in reporting threshold would allow the Agency to comprehensively track all CO_2 supply (as reported in Suppliers of CO_2, subpart PP) that is injected underground. This approach is consistent with the all-in requirements in the MRR for suppliers of petroleum, natural gas, and coal-to-liquid products (subparts LL, MM, and NN), producers of industrial gases (subpart OO), and suppliers of CO_2 (subpart PP). It was reasonable to require all of the facilities in these source categories to report because it would result in the most comprehensive accounting possible, simplify the rule, and permit facilities to quickly determine whether or not they must report; the same rationale applies for this source category proposed today. Furthermore, it would create a uniform burden for all covered facilities, ensuring a level playing field in, and preventing fragmentation of, the ER sector. EPA has estimated the cost for CO_2 injection facilities to comply with the minimum reporting requirements in this proposed rule and has determined that the burden would be small, given the equipment and data collection efforts already in place at ER projects.

Under this action, EPA is proposing that the subset of CO_2 injection facilities that are conducting GS (i.e. a GS facility) must report to EPA a second tier of data. EPA considered whether a threshold should apply to this second tier of data given that it would place a reporting burden on GS facilities. However, EPA could not perform an analysis on GS facilities based on emissions without data on actual or expected GS facility emissions. EPA also could not perform a threshold analysis based on injection due to the uncertainty around predictions of injection quantities for potential GS facilities. In addition, it is difficult to predict how many injection facilities would choose to report GS. Therefore, EPA is proposing to exempt GS R&D projects but otherwise require all GS facilities to comply with the GS monitoring, reporting, and verification requirements of subpart RR, and that they report fugitive, vented, and combustion emissions from surface equipment (under subpart W, RR, or C, as applicable). An all-in threshold will allow EPA to work with the early-movers of this nascent industry and to strengthen EPA's understanding of GS.

5.2 National Cost Estimates

The total annualized costs incurred under the rule by these entities would be approximately $713,000 (in 2008$). This includes a public sector burden estimate of $344,000 for program implementation and verification activities. The typical annual cost for a CO_2 injection facility with no GS is $4,000 per year.

Table 5-2. National Annualized Mandatory Reporting Costs Estimates: Subpart RR

Type	Number	Metric Tons CO_2 Injected per Year	Total Annual Cost (thousand, 2008$)
R&D	9	5,320,000	$37
CO_2 Injection Facilities (No GS)[a]	80	36,815,442	$332
Private Sector, Total All Projects	89	45,435,442	$369
Private Sector, Average ($/ton)			$0.01
Public Sector, Total			$344
National Total			$713

[a]Includes Class II ER projects

Given uncertainties related to project adoption and the costs of the reporting program, EPA also considered two other private costs scenarios (one higher and one lower than the reference cost scenario) in order to assess a range of economic impacts on affected entities (Table 5-3).

Table 5-3. Annualized Mandatory Reporting Costs per Project (2008$): Subpart RR

	Average		
		Alternative Cost Scenarios	
Type	Reference ($1,000)	Low ($1,000)	High ($1,000)
GS Facilities (commercial saline)	$289	$7	$470
GS Facilities (ER opt in)	$1,679	$1,485	$1,804
CO_2 Injection Facilities (No GS)[a]	$4	$4	$4

[a]Includes Class II ER projects

5.2.1 National Cost Estimates Under Alternative GS Facilities (ER opt in) Outcomes

Currently, the number of ER operations that would choose to report as GS Facilities (ER opt in) is unknown and EPA could not identify any information or analysis to estimate this quantity. As a result, two additional scenarios of the have been considered to represent medium and high outcomes. As shown in Tables 5-4, national cost estimate is $24 million under the medium ER opt in outcome. As shown in Tables 5-5, national cost estimate is $79 million under the high ER opt in outcome.

Table 5-4. National Annualized Mandatory Reporting Costs Estimates (2008): All Anthropogenic CO_2 Projects

Type	Number	Metric Tons CO_2 Injected per Year	Total Annual Cost (thousand, 2008$)
R&D	9	5,320,000	$37
GS Facilities (ER opt in)	16	6,972,040	$23,423
CO_2 Injection Facilities (No GS)[a]	64	33,143,402	$266
Private Sector, Total All Projects	89	45,435,442	$23,726
Private Sector, Average ($/ton)			$0.52
Public Sector, Total			$344
National Total			$24,069

[a]Includes Class II ER projects

Table 5-5. National Annualized Mandatory Reporting Costs Estimates (2008$): All Anthropogenic 50 Percent of Other CO_2 Projects

Type	Number	Metric Tons CO_2 Injected per Year	Total Annual Cost (thousand, 2008$)
R&D	9	5,320,000	$37
GS Facilities (ER opt in)	48	23,543,741	$79,071
CO_2 Injection Facilities (No GS)[a]	32	16,571,701	$133
Private Sector, Total All Projects	89	45,435,442	$79,241
Private Sector, Average ($/ton)			$1.74
Public Sector, Total			$344
National Total			$79,585

[a]Includes Class II ER projects

5.2.2 National Cost Estimates Under Alternative GS Facilities (Commercial Saline) Outcomes

EPA considered two additional scenarios of the number of large scale saline aquifer GS (commercial saline) project deployment over the next 25 years: low (3 projects), medium (6 projects), and high (9 projects). The medium scenario is based on large scale saline project deployment projected in the cost analysis prepared for the UIC Class VI rule proposed on July 25, 2008 (73 FR 43492). The national cost estimates estimate increase $867,000 under the low outcome; $1.7 million under the medium outcome, and $2.6 million under the high outcome.

5.3 Economic Impact Analysis

EPA assessed how the regulatory program may influence the profitability of companies by comparing the monitoring program costs to total sales (i.e., a “sales” test). Given limited data on commercial geological sequestration operations, EPA restricted the analysis to ER operations. As shown in Table 5-2, ER activities account for approximately 90 percent of the project population. To do this, we divided the average annualized mandatory reporting costs per field by the estimated revenue for a representative field.

Sales Test Ratio= Average Cost (Table 5-3)/Estimated revenue (Table 5-6)

5.3.1 Revenue Estimate for a Representative Commercial ER Operation

EPA obtained national production statistics from the latest Department of Energy report about CO_2 ER Technologies (DOE, 2009). Data suggest a typical operation produces approximately 776,000 barrels of oil per year. Using the DOE choice of an average long-term price of oil ($70), EPA estimated total revenue of $54.3 million per year. To enhance the transparency of the calculation, we provide data, sources, and methods in Table 5-6.

Table 5-6. Estimated Annual Revenue for a Representative Commercial ER Field Operation (2008)

Label	Variable	Value	Source and Calculation Method
A	Barrels Per Day	250,000	DOE, 2009 p: 19
B	Barrels per year	77,562,500	A × 0.85 × 365
C	Population	100	DOE, 2009 p: 19
D	Average Barrels per year	775,625	B / C
E	Price per barrel	$70	DOE, 2009 p: 2
F	Total Revenue ($ milliion)	$54	D× E

Source: EPA calculations using data from DOE (2009). Storing CO_2 and Producing Domestic Crude Oil with Next Generation CO_2-ER Technology, accessed October 28, 2009.

5.3.2 Sales Test Results

As shown in Table 5-7 sales test ratios are between 3.1 to 3.3 percent for GS facilities (ER opt in). In contrast, CO_2 injection facilities (no GS, which includes Class II ER operations) sales test ratios are below 0.01 percent.

Table 5-7. Sales Tests for Representative Commercial ER Field Operations

	Cost-to-Sales Ratios (CSRs)		
		Alternative Cost Scenarios	
Type	**Reference**	**Low**	**High**
GS Facilities (ER opt in)	3.1%	2.7%	3.3%
CO_2 Injection Facilities (No GS)[a]	<0.01%	<0.01%	<0.01%

[a]Includes Class II ER operations

5.4 Assessing Economic Impacts on Small Entities

The first step in this assessment was to determine whether the rule will have a significant impact on a substantial number of small entities (SISNOSE). To make this determination, EPA used a screening analysis that allows us to indicate whether EPA can certify the rule as not having a SISNOSE. The elements of this analysis included

- identifying affected sectors and entities,
- selecting and describing the measures and economic impact thresholds used in the analysis, and
- determining SISNOSE certification category.

5.4.1 Identify Affected Sectors and Entities

For the purposes of assessing the impacts of the rule on small entities, we defined a small entity as (1) a small business, as defined by SBA's regulations at 13 CFR Part 121.201; (2) a small governmental jurisdiction that is a government of a city, county, town, school district, or special district with a population of less than 50,000; or (3) a small organization that is any not-for-profit enterprise that is independently owned and operated and is not dominant in its field.

For the Carbon Dioxide Injection and Geologic Sequestration Reporting Rule, small entity is defined as a small business as defined by the Small Business Administration's regulations at 13 CFR 121.201; according to these size standards, ultimate parent companies owning oil and gas extraction operations (NAICS 211) are categorized as small if the total number of employees at the firm is fewer than 500.

The Oil & Gas Journal publishes a list of companies owning active U.S. CO_2 ER projects in 2008 (OGJ, 2008). EPA's initial review of publicly available sales and employment databases suggest up to 9 of the 23 companies listed in the OGJ survey have fewer than 500 employees. EPA continues to collect other information about corporate structures of these 9 companies to assess whether these companies are owned by larger parent companies.

5.4.2 Develop Small Entity Economic Impact Measures

The sales test examined the average total annualized mandatory reporting costs per ER field to a representative measure of revenue. Details are provided in section 5.3.

5.4.3 Results of Screening Analysis

The Regulatory Flexibility Act generally requires an agency to prepare a regulatory flexibility analysis of any rule subject to notice and comment rulemaking requirements under the Administrative Procedure Act or any other statute, unless the agency certifies that the rule will not have a significant economic impact on a substantial number of small entities.

After considering the economic impact of the rule on small entities, EPA has concluded that this action will not have a significant economic impact on a substantial number of small entities. Currently EPA believes small ER operations will most likely be CO_2 injection facilities (no GS), including Class II ER projects. The average ratio of annualized reporting program costs to revenues of a typical ER operation likely owned by representative small enterprises is less than 1%.

Although this rule will not have a significant economic impact on a substantial number of small entities, EPA nonetheless took several steps to reduce the impact of this rule on small entities. For example, EPA is proposing monitoring and reporting requirements that build off of the UIC program. In addition, EPA is proposing equipment and methods that may already be in use by a facility for compliance with its UIC permit. Also, EPA is requiring annual reporting instead of more frequent reporting.

In addition to the public hearing that EPA plans to hold, EPA has an open door policy, similar to the outreach conducted during the development of the proposed and final Mandatory GHG Reporting Rule. Details of these meetings are available in the docket (EPA-HQ-OAR-2009-0926).

5.5 Characterization of Benefits of Subpart RR of the Mandatory Reporting Rule

EPA examined the potential benefits of the Carbon Dioxide Injection and Geologic Sequestration Reporting Rule. EPA's previous analysis of the GHG reporting rule discussed the benefits of a reporting system with respect to policy making relevance, transparency issues, and market efficiency. Instead of a quantitative analysis of the benefits, EPA conducted a systematic literature review of existing studies including government, consulting, and scholarly reports.

A mandatory reporting system will benefit the public by increased transparency of facility GHG data. Transparent, public data on GHGs allows for accountability of polluters to the public stakeholders who bear the cost of the pollution. Citizens, community groups, and labor unions have made use of data from Pollutant Release and Transfer Registers to negotiate directly with polluters to lower emissions, circumventing greater government regulation. Publicly available emissions data also will allow individuals to alter their consumption habits based on the GHG emissions of producers.

The greatest benefit of mandatory reporting of GHGs to government will be realized in developing future GHG policies. For example, in the EU's Emissions Trading System, a lack of accurate monitoring at the facility level before establishing CO_2 allowance permits resulted in allocation of permits for emissions levels an average of 15 percent above actual levels in every country except the United Kingdom.

Benefits to industry of GHG monitoring include the value of having independent, verifiable data to present to the public to demonstrate appropriate environmental stewardship, and a better understanding of their emission levels and sources to identify opportunities to reduce emissions. Such monitoring allows for inclusion of standardized GHG data into environmental management systems, providing the necessary information to achieve and disseminate their environmental achievements.

Standardization will also be a benefit to industry, once facilities invest in the institutional knowledge and systems to report GHG data, the cost of monitoring should fall and the accuracy of the accounting should improve. A standardized reporting program will also allow for facilities to benchmark themselves against similar facilities to understand better their relative standing within their industry.

Data on CO_2 injection and GS are critical to informing CAA GHG policies. This data would provide information and transparency on the amount of CO_2 injected and geologically sequestered in the United States and, in combination with other subparts of the MRR, would enable EPA to track the flow of CO_2 across a CCS system. In addition, this information would enable EPA to monitor the growth and efficacy of GS (and therefore CCS) as a GHG mitigation technology over time and to evaluate relevant policy options. For example, EPA would be able to track whether incentives or regulations are needed to encourage faster or further GS project development. EPA would also be able to track whether ER sites are reporting GS and consider whether incentives or regulations are needed. Where ER facilities are reporting GS, EPA would be able to evaluate ER as a potentially non-emissive end use. In combination with subpart PP, EPA would be able to reconcile this data with CO_2 supplied in order to better understand the quantity of CO_2 supplied to emissive and non-emissive end uses.

SECTION 6
STATUTORY AND EXECUTIVE ORDER REVIEWS

This section describes EPA's compliance with several applicable executive orders and statutes during the development of the proposed Carbon Dioxide Injection and Geologic Sequestration Reporting Rule, subpart RR under Track II of the GHG reporting rule.

6.1 Executive Order 12866: Regulatory Planning and Review

Under Section 3(f)(1) of Executive Order 12866 (58 FR 51735, October 4, 1993), this proposed action is not by itself an "economically significant regulatory action" because it is unlikely to have an annual economic effect of less than $100 million. EPA's cost analysis, presented in Section 4 of the Economic Impact Analysis (EIA), estimates that for the minimum reporting under the recommended regulatory option, the total annualized cost of the rule will be approximately 713,000 (in 2008$) during the first year of the program and $713,000 in subsequent years (344,000 of programmatic costs to the Agency). This proposed action adds Subpart RR to the mandatory GHG reporting rule, which was a significant regulatory action. Thus, EPA has chosen to analyze the impacts of Subpart RR as if it were significant. EPA submitted this proposed action to the Office of Management and Budget (OMB) for review under Executive Order 12866, and any changes made in response to OMB recommendations have been documented in the docket for this proposed action.

In addition, EPA prepared this EIA, including an analysis of the potential costs associated with this action. In this report, EPA has identified the regulatory options considered, their costs, the emissions that would likely be reported under each option, and explained the selection of the option chosen for the rule. The costs of the rule are reported in Section 4, and the economic impacts and qualitative benefits assessment are reported in Section 5. Overall, EPA has concluded that the costs of the Carbon Dioxide Injection and Geologic Sequestration Reporting Rule are outweighed by the potential benefits of more comprehensive information about CO_2 injection.

6.2 Paperwork Reduction Act

The information collection requirements in this proposed rule have been submitted for approval to the Office of Management and Budget (OMB) under the Paperwork Reduction Act, 44 U.S.C. 3501 *et seq*. The Information Collection Request (ICR) document prepared by EPA has been assigned EPA ICR number 2372.01

EPA has identified the following goals of the mandatory GHG reporting system:

- Obtain data that is of sufficient quality that it can be used to analyze and inform the development of a range of future climate change policies and potential regulations.
- Balance the rule's coverage to maximize the amount of emissions reported while excluding small emitters.
- Create reporting requirements that are, to the extent possible and appropriate, consistent with existing GHG reporting programs in order to reduce reporting burden for all parties involved.

The information from CO_2 injection and geologic sequestration facilities will allow EPA to make well-informed decisions about whether and how to use the CAA to regulate these facilities and encourage voluntary reductions. Because EPA does not yet know the specific policies that will be adopted, the data reported through the mandatory reporting system should be of sufficient quality to inform policy and program development. Also, consistent with the Appropriations Act, the reporting rule covers a broad range of sectors of the economy.

This information collection is mandatory and will be carried out under CAA Sections 114. Information identified and marked as Confidential Business Information (CBI) will not be disclosed except in accordance with procedures set forth in 40 CFR Part 2. However, emissions information collected under CAA Sections 114 generally cannot be claimed as CBI and will be made public.[47]

The projected average ICR cost and respondent burden is $0.8 million and 4,510 hours per year. The estimated average annual burden per response is 6.8 hours; the frequency of response is annual for all respondents that must comply with the rule's reporting requirements, except for electricity-generating units that are already required to report quarterly under 40 CFR Part 75 (ARP); and the estimated average number of likely respondents per year is 89. The cost burden to respondents resulting from the collection of information includes the total capital and start-up cost annualized over the equipment's expected useful life (averaging $0.1 million per year) a total operation and maintenance component (averaging $0.3 million per year), and a labor cost component (averaging $0.3 million per year). Burden is defined at 5 CFR Part 1320.3(b).

These cost numbers differ from those shown elsewhere in the EIA because ICR costs represent the average cost over the first three years of the rule, but costs are reported elsewhere

[47] Although CBI determinations are usually made on a case-by-case basis, EPA has issued guidance in an earlier Federal Register notice on what constitutes emissions data that cannot be considered CBI (956 FR 7042 – 7043, February 21, 1991). As discussed in Section II.R of the preamble to the rule, EPA will be initiating a separate notice and comment process to make CBI determinations for the data collected under this proposed rulemaking.

in the EIA for the first year of the rule. Also, the total cost estimate of the rule in the EIA includes the cost to the Agency to administer the program. The ICR differentiates between respondent burden and cost to the Agency.

An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. The OMB control numbers for EPA's regulations in 40 CFR are listed in 40 CFR Part 9. When this ICR is approved by OMB, the Agency will publish a technical amendment to 40 CFR part 9 in the Federal Register to display the OMB control number for the approved information collection requirements contained in the final rule.

6.3 Regulatory Flexibility Act

The Regulatory Flexibility Act generally requires an agency to prepare a regulatory flexibility analysis of any rule subject to notice and comment rulemaking requirements under the Administrative Procedure Act or any other statute, unless the agency certifies that the rule will not have a significant economic impact on a substantial number of small entities. Small entities include small businesses, small governmental jurisdictions, and small not-for-profit enterprises.

The first step in this assessment was to determine whether the rule will have a significant impact on a substantial number of small entities (SISNOSE). To make this determination, EPA used a screening analysis that allows us to indicate whether EPA can certify the rule as not having a SISNOSE. The elements of this analysis included

- identifying affected sectors and entities,
- selecting and describing the measures and economic impact thresholds used in the analysis, and
- determining SISNOSE certification category.

6.3.1 Identify Affected Sectors and Entities

For the purposes of assessing the impacts of the rule on small entities, we defined a small entity as (1) a small business, as defined by SBA's regulations at 13 CFR Part 121.201; (2) a small governmental jurisdiction that is a government of a city, county, town, school district, or special district with a population of less than 50,000; or (3) a small organization that is any not-for-profit enterprise that is independently owned and operated and is not dominant in its field.

For the Carbon Dioxide Injection and Geologic Sequestration Reporting Rule, small entity is defined as a small business as defined by the Small Business Administration's regulations at 13 CFR 121.201; according to these size standards, ultimate parent companies owning oil and gas extraction operations (NAICS 211) are categorized as small if the total number of employees at the firm is fewer than 500.

The Oil & Gas Journal publishes a list of companies owning active U.S. CO_2 ER projects in 2008 (OGJ, 2008). EPA's initial review of publicly available sales and employment databases suggest up to 9 of the 23 companies listed in the OGJ survey have fewer than 500 employees. EPA continues to collect other information about corporate structures of these 9 companies to assess whether these companies are owned by larger parent companies.

6.3.2 Develop Small Entity Economic Impact Measures

These sales test examined the average total annualized mandatory reporting costs per ER field to a representative measure of revenue. Details are provided in section 5.3.

6.3.3 Results of Screening Analysis

The Regulatory Flexibility Act generally requires an agency to prepare a regulatory flexibility analysis of any rule subject to notice and comment rulemaking requirements under the Administrative Procedure Act or any other statute, unless the agency certifies that the rule will not have a significant economic impact on a substantial number of small entities.

After considering the economic impact of the rule on small entities, EPA has concluded that this action will not have a significant economic impact on a substantial number of small entities. Currently EPA believes small ER operations will most likely be CO_2 injection facilities (no GS), including Class II ER projects. As shown in Table 5-7, the average ratio of annualized reporting program costs to revenues of a typical ER operation likely owned by model small enterprises was less than 1%.

Although this rule will not have a significant economic impact on a substantial number of small entities, EPA nonetheless took several steps to reduce the impact of this rule on small entities. For example, EPA is proposing monitoring and reporting requirements that build off of the UIC program. In addition, EPA is proposing equipment and methods that may already be in use by a facility for compliance with its UIC permit. Also, EPA is requiring annual reporting instead of more frequent reporting.

In addition to the public hearing that EPA plans to hold, EPA has an open door policy, similar to the outreach conducted during the development of the proposed and final Mandatory GHG Reporting Rule. Details of these meetings are available in the docket (EPA-HQ-OAR-2008-0508).

6.4 Unfunded Mandates Reform Act

Title II of the Unfunded Mandates Reform Act of 1995 (UMRA), P.L. 104-4, establishes requirements for federal agencies to assess the effects of their regulatory actions on state, local, and tribal governments and the private sector. Under Section 202 of the UMRA, EPA generally must prepare a written statement, including a cost-benefit analysis, for final rules with "federal mandates" that may result in expenditures to state, local, and tribal governments, in the aggregate, or to the private sector, of $100 million or more in any one year.

This proposed rule does not contain a Federal mandate that may result in expenditures of $100 million or more for State, local, and tribal governments, in the aggregate, or the private sector in any one year. Overall, EPA estimates that the total annualized costs of this proposed rule are approximately $713,000 per year. Thus, this proposed rule is not subject to the requirements of sections 202 or 205 of UMRA.

This proposed rule is also not subject to the requirements of section 203 of UMRA because it contains no regulatory requirements that might significantly or uniquely affect small governments. Facilities subject to the proposed rule include facilities that inject CO_2 for enhanced recovery of crude oil, and those that sequester CO_2. None of the facilities currently known to undertake these activities are owned by small governments.

6.5 Executive Order 13132: Federalism

Executive Order 13132, entitled "Federalism" (64 FR 43255, August 10, 1999), requires EPA to develop an accountable process to ensure "meaningful and timely input by state and local officials in the development of regulatory policies that have federalism implications." "Policies that have federalism implications" is defined in the executive order to include regulations that have "substantial direct effects on the states, on the relationship between the national government and the states, or on the distribution of power and responsibilities among the various levels of government."

This proposed rule does not have federalism implications. It will not have substantial direct effects on the states, on the relationship between the national government and the states, or on the distribution of power and responsibilities among the various levels of government, as specified in Executive Order 13132.

This regulation applies to public- or private-sector facilities that inject GHG underground. Few government facilities would be affected. This regulation also does not limit the power of states or localities to collect GHG data and/or regulate GHG emissions. Thus, Executive Order 13132 does not apply to this proposed rule.

In the spirit of Executive Order 13132, and consistent with EPA policy to promote communications between EPA and State and local governments, EPA specifically solicits comment on this proposed action from State and local officials.

6.6 Executive Order 13175: Consultation and Coordination with Indian Tribal Governments

Executive Order 13175, entitled “Consultation and Coordination with Indian Tribal Governments” (59 FR 22951, November 6, 2000), requires EPA to develop an accountable process to ensure “meaningful and timely input by tribal officials in the development of regulatory policies that have tribal implications.”

This proposed rule is not expected to have tribal implications, as specified in Executive Order 13175. This regulation applies to facilities that facilities that inject GHG underground. Few facilities expected to be affected by the rule are likely to be owned by tribal governments. Thus, Executive Order 13175 does not apply to this proposed rule.

Although Executive Order 13175 does not apply to this proposed rule, EPA sought opportunities to provide information to tribal governments and representatives during development of the MRR rule. In consultation with EPA’s American Indian Environment Office, EPA’s outreach plan for the MRR included tribes. For a complete list of tribal contacts, see the “Summary of EPA Outreach Activities for Developing the Greenhouse Gas Reporting Rule,” in the Docket for this proposed rulemaking (EPA-HQ-OAR-2008-0508-055). In addition to the consultation activities supporting the MRR, EPA continues to provide information to tribal governments and representatives during development of the Track II rules such as this proposed rulemaking. EPA specifically solicits additional comment on this proposed action from tribal officials.

6.7 Executive Order 13045: Protection of Children from Environmental Health and Safety Risks

EPA interprets Executive Order 13045 (62 F.R. 19885, April 23, 1997) as applying only to those regulatory actions that concern health or safety risks, such that the analysis required under Section 5-501 of the executive order has the potential to influence the regulation. This action is not subject to Executive Order 13045 because it does not establish an environmental standard intended to mitigate health or safety risks.

6.8 Executive Order 13211: Actions that Significantly Affect Energy Supply, Distribution, or Use

This proposed rule is not a "significant energy action" as defined in Executive Order 13211 (66 FR 28355, May 22, 2001) because it is not likely to have a significant adverse effect on the supply, distribution, or use of energy. Further, we have concluded that this proposed rule is not likely to have any adverse energy effects.

This proposal relates to monitoring, reporting, and recordkeeping at facilities that directly inject CO_2 for enhanced recovery of oil or geologic sequestration; it does not adversely affect energy supply, distribution or use. Therefore, we conclude that this proposed rule is not likely to have any adverse effects on energy supply, distribution, or use.

6.9 National Technology Transfer Advancement Act

Section 12(d) of the National Technology Transfer and Advancement Act of 1995 (NTTAA), Public Law No. 104-113 (15 U.S.C. 272 note) directs EPA to use voluntary consensus standards in its regulatory activities unless to do so would be inconsistent with applicable law or otherwise impractical. Voluntary consensus standards are technical standards (e.g., materials specifications, test methods, sampling procedures, and business practices) that are developed or adopted by voluntary consensus standards bodies. NTTAA directs EPA to provide Congress, through OMB, with explanations when the Agency decides not to use available and applicable voluntary consensus standards.

This proposed rulemaking involves technical standards. EPA proposes to use voluntary consensus standards from six different voluntary consensus standards bodies: American Society for Testing and Material (ASTM), American Society of Mechanical Engineers (ASME), International Organization for Standardization (ISO), Gas Processors Association (GPA), American Gas Association (AGA), and American Petroleum Institute (API). These voluntary consensus standards will help facilities monitor, report, and keep records of GHG emissions associated with their CO_2 injection and geologic sequestration activities. No new test methods were developed for this proposed rule. Instead, from existing rules for source categories and voluntary GHG programs, EPA identified existing means of monitoring, reporting, and keeping records. The existing methods (voluntary consensus standards) include a broad range of measurement techniques, methods to measure gas or liquid flow, and methods to gauge and measure petroleum and petroleum products. The test methods are incorporated by reference into the rule and are available as specified in Section 98.6 of subpart A.

By incorporating voluntary consensus standards into this proposed rule, EPA is both meeting the requirements of the NTTAA and presenting multiple options and flexibility for complying with the proposed rule. EPA welcomes comments on this aspect of the proposed rulemaking and, specifically, invites the public to identify potentially-applicable voluntary consensus standards and to explain why such standards should be used in this proposed regulation.

6.10 Executive Order 12898: Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations

Executive Order 12898 (59 FR 7629, February 16, 1994) establishes federal executive policy on environmental justice. Its main provision directs federal agencies, to the greatest extent practicable and permitted by law, to make environmental justice part of their mission by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects of their programs, policies, and activities on minority populations and low-income populations in the United States.

EPA has determined that this proposed rule will not have disproportionately high and adverse human health or environmental effects on minority or low-income populations because it does not affect the level of protection provided to human health or the environment. This proposed rule does not affect the level of protection provided to human health or the environment because it is a rule addressing information collection and reporting procedures.

SECTION 7
CONCLUSIONS

EPA is proposing to add Subpart RR to the existing Mandatory Reporting of Greenhouse Gases Program established under 40 CFR 98 to track the fate of CO_2 injected underground and confirm CO_2 sequestration volumes. The proposed approach is tiered. First, a set of reporting requirements is proposed to cover facilities that inject CO_2 underground regardless of the purpose of injection. Second, a subset of facilities that inject CO_2 and conduct geologic sequestration (GS) are subject to an additional set of requirements.

7.1 Summary of Selected Regulatory Alternative

EPA is proposing that all CO_2 injection facilities would be required to report the minimum information in subpart RR (quantity of CO_2 injected, quantity of CO_2 transferred onsite from offsite, and source of the CO_2 if known) at no threshold. An all-in reporting threshold would allow the Agency to comprehensively track all CO_2 supply (as reported in Suppliers of CO_2, subpart PP) that is injected underground. This approach is consistent with the all-in requirements in the MRR for suppliers of petroleum, natural gas, and coal-to-liquid products (subparts LL, MM, and NN), producers of industrial gases (subpart OO), and suppliers of CO_2 (subpart PP). It was reasonable to require all of the facilities in these source categories to report because it would result in the most comprehensive accounting possible, simplify the rule, and permit facilities to quickly determine whether or not they must report; the same rationale applies for this source category proposed today. Furthermore, it would create a uniform burden for all covered facilities, ensuring a level playing field in, and preventing fragmentation of, the ER sector. EPA has estimated the cost for CO_2 injection facilities to comply with the minimum reporting requirements in this proposed rule and has determined that the burden would be small, given the equipment and data collection efforts already in place at ER projects.

Under this action, EPA is proposing that the subset of CO_2 injection facilities that are conducting GS (i.e. a GS facility) must report to EPA a second tier of data. EPA considered whether a threshold should apply to this second tier of data given that it would place a reporting burden on GS facilities. However, EPA could not perform an analysis on GS facilities based on emissions without data on actual or expected GS facility emissions. EPA also could not perform a threshold analysis based on injection due to the uncertainty around predictions of injection quantities for potential GS facilities. In addition, it is difficult to predict how many injection facilities would choose to report GS. Therefore, EPA is proposing to exempt GS R&D projects but otherwise require all GS facilities to comply with the GS monitoring, reporting, and verification requirements of subpart RR, and that they report fugitive, vented, and combustion emissions from surface equipment (under subpart W, RR, or C, as applicable). An all-in threshold will allow EPA to work with the early-movers of this nascent industry and to strengthen EPA's understanding of GS.

7.2 Estimated Costs and Impacts of the Mandatory GHG Reporting Program

Under the rule, EPA estimates that 89 fields would be covered by the rule, injecting approximately 40 $MtCO_2$ per year. The total annualized costs incurred under the rule by these entities would be approximately $713,000 (in 2008$). This includes a public sector burden estimate of $344,000 for program implementation and verification activities. These costs are distributed to several economic sectors and represent approximately 0.0001% of 2008 gross domestic product; overall, EPA does not believe the rule will have a significant macroeconomic impact on the national economy or on small entities within those sectors.

7.2.1 Alternative Scenarios Considered

7.2.1.1 GS Facilities (ER opt in) Outcomes

Currently, the number of GS Facilities (ER opt in) is unknown and EPA could not identify any information or analysis to estimate this quantity. As a result, two additional scenarios of the have been considered to represent medium and high outcomes. As shown in Tables 5-4, national cost estimate is $24 million under the medium ER opt in outcome. As shown in Tables 5-5, national cost estimate is $79 million under the high ER opt in outcome.

7.2.1.2 GS Facilities (Commercial Saline) Outcomes

EPA considered two additional scenarios of the quantity of commercial saline project outcomes: low (3 projects), medium (6 projects), and high (9 projects). The national cost estimates estimate increase $867,000 under the low outcome; $1.7 million under the medium outcome, and $2.6 million under the high outcome.

SECTION 8
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